August 14, 2006

Mr. T. Palmisano
Site Vice President
Prairie Island Nuclear Generating Plant
Nuclear Management Company, LLC
1717 Wakonade Drive East
Welch, MN 55089

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2 NRC INTEGRATED INSPECTION REPORT 05000282/2006003; 05000306/2006003

Dear Mr. Palmisano:

On June 30, 2006, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Prairie Island Nuclear Generating Plant, Units 1 and 2. The enclosed report documents the inspection findings which were discussed on July 12, 2006, with you and other members of your staff.

This inspection examined activities conducted under your license as they relate to safety and to compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, there were three NRC-identified and one self-revealed findings of very low safety significance noted. All these findings involved violations of NRC requirements. In addition, one NRC-identified issue was reviewed under the NRC traditional enforcement process and was determined to be a Severity Level IV violation of NRC requirements. However, because these violations were of very low safety significance, not willful, and because they were entered into your corrective action program, the NRC is treating these issues as Non-Cited Violations in accordance with Section VI.A.1 of the NRC's Enforcement Policy. Additionally, four licensee-identified violations are listed in Section 4OA7 of this report.

If you contest the subject or severity of a Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the Resident Inspector Office at the Prairie Island Nuclear Generating Plant.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA Mark A. Ring acting for/

Richard A. Skokowski, Chief
Branch 3
Division of Reactor Projects

Docket Nos. 50-282; 50-306
License Nos. DPR-42; DPR-60

Enclosure: Inspection Report 05000282/2006003; 05000306/2006003
w/Attachment: Supplemental Information

cc w/encl: C. Anderson, Senior Vice President, Group Operations
M. Sellman, Chief Executive Officer and Chief Nuclear Officer
Regulatory Affairs Manager
J. Rogoff, Vice President, Counsel & Secretary
Nuclear Asset Manager
State Liaison Officer, Minnesota Department of Health
Tribal Council, Prairie Island Indian Community
Administrator, Goodhue County Courthouse
Commissioner, Minnesota Department
of Commerce
Manager, Environmental Protection Division
Office of the Attorney General of Minnesota

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-282; 50-306
License Nos:	DPR-42; DPR-60
Report No:	05000282/2006003; 05000306/2006003
Licensee:	Nuclear Management Company, LLC
Facility:	Prairie Island Nuclear Generating Plant, Units 1 and 2
Location:	1717 Wakonade Drive East Welch, MN 55089
Dates:	April 1 through June 30, 2006
Inspectors:	J. Adams, Senior Resident Inspector D. Karjala, Resident Inspector M. Holmberg, Reactor Inspector J. Neurauter, Reactor Inspector D. Jones, Reactor Inspector M. Mitchell, Radiation Specialist M. Phalen, Radiation Specialist J. Robbins, Reactor Engineer
Approved by:	Richard A. Skokowski, Chief Branch 3 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000282/2006003, 05000306/2006003; 4/01/06 - 6/30/06; Prairie Island Nuclear Generating Plant, Units 1 and 2; Inservice Inspection Activities, Reactor Vessel Head Replacement, Radiation Protection, and other activities.

This report covers a 3-month period of baseline resident inspection and announced baseline inspection on radiation protection, inservice inspections, and reactor vessel head replacement. The inspections were conducted by the resident inspectors and inspectors from the Region III office. One Severity Level IV violation and four findings with associated non-cited violations were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, “Significance Determination Process” (SDP). Findings for which the SDP does not apply may be “Green” or be assigned a severity level after NRC management review. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 3, dated July 2000.

A. Inspector-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a Non-Cited Violation of 10 CFR Part 50 Appendix B, Criterion V for a combination of an inadequate procedure and a failure to implement the requirements of Surveillance Procedure 1293, Inspection of Flood Control Measures and the Shelf Life Program Procedure FP-SC-PE-05. Specifically, the licensee failed to order and maintain the correct type of Deck-O-Seal sealant to facilitate installation of flood doors and panels in accordance with plant abnormal procedures.

  The finding was more than minor because it closely matched example 2E of Inspection Manual Chapter 0612, Appendix E. The inspectors determined the finding to be of very low safety significance following a review of a licensee’s condition evaluation concluding that the finding did not increase the likelihood of the external flooding event affecting plant safety-related systems or components. (Section 4OA5)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a Severity Level IV Non-Cited Violation associated with the failure to perform an adequate safety evaluation review as required by 10 CFR 50.59 for the changes made to the Updated Safety Analysis Report (USAR). In safety evaluation 1052, Revision 0, the licensee failed to provide a basis for the determination, that removing the maximum reactor vessel head lift elevation and reference to the associated load drop analysis calculation from the USAR, was acceptable without a license amendment. Specifically, the licensee determined that their load drop analysis was neither a regulatory requirement nor a licensing commitment and could be removed from the USAR. Within the 10 CFR 50.59 evaluation, the licensee failed to provide a basis for why the removal of this lift elevation restriction from the USAR did not present more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system, or component important to safety if the reactor vessel head was dropped at an elevation higher than that evaluated in the load drop calculation with irradiated fuel in the reactor core.

Because the issue affected the NRC's ability to perform its regulatory function, this finding was evaluated using the traditional enforcement process. The finding was determined to be more than minor because the inspectors could not reasonably determine that the USAR change, which had the potential to adversely affect equipment important to safety, would not have ultimately required NRC approval. The finding was determined to be of very low safety significance (Green) because the inspectors answered "no" to question 1 under the Mitigating Systems Cornerstone column of the Phase 1 worksheet. Specifically, the licensee had not performed a reactor vessel head lift where the lift height was in excess of the elevation evaluated in their load drop analysis, and licensee maintenance procedures limited the maximum allowed reactor vessel head lift height to be less than the elevation evaluated in their load drop analysis. (Section 1R02.1.b.1)

Cornerstone: Occupational Radiation Safety

Green. A finding of very low safety significance and associated Non-Cited Violation (NCV) were inspector-identified during a walkdown in Unit 1 containment. The inspectors identified that a swing gate barrier to a High Radiation Area (HRA) was left in the open position due to misalignment of the gate in the stand. The licensee corrected the barrier misalignment and verified other HRA barriers in containment were properly operating and positioned. Radiation workers in containment were not self-checking to assure that the barriers were placed back into the correct position after traversing the HRA. The licensee entered this finding into the corrective action program.

The finding was more than minor because it was associated with the Occupational Radiation Safety cornerstone, and potentially affected the cornerstone attribute of program and process for radiation worker performance. The finding was determined to be of very low safety significance because it did not involve an As-Low-As-Reasonably-Achievable (ALARA) issue, as collective dose was not a factor and no individual received an unintended dose as a result of the barrier non-compliance; there was not a substantial potential for a worker overexposure; and the licensee's ability to assess worker dose was not compromised. Since the principal cause of the problem was a human performance deficiency, the finding also relates to the cross-cutting area of human performance. (Section 2OS1)

Green. A self-revealing finding of very low safety significance and associated NCV were identified when 110 radiation workers were contaminated as a result of opening steam generator manways during the Unit 1 1R24 refueling outage. Specific ALARA planning assessments did not acknowledge airborne concentrations of radioactivity may be subject to change. Additionally, the ALARA planning for this work did not consider the effect of engineering safety systems operation or malfunction on other work areas in containment, consequently when the work area was set up and initial work commenced, the focus was on the immediate work area only, and the result was elevated iodine-131 levels throughout containment. The licensee evacuated containment, identified the source of airborne contamination, and repositioned and secured an air handling hose to the containment clean-up filter. The event was entered into the licensee's corrective action program.

The finding was more than minor because it was associated with the Occupational Radiation Safety cornerstone, and potentially affected the cornerstone attribute of program and process for ALARA planning and exposure/contamination control. The finding was determined to be of very low safety significance because although the finding did involve an ALARA planning issue and resulted in unintended exposure to personnel, personnel doses were well below regulatory limits. (Section 2OS2)

Cornerstone: Public Radiation Safety

Green. A finding of very low safety significance and associated NCV were inspector-identified for the failure to establish adequate written procedure(s) for Offsite Dose Calculation Manual (ODCM) implementation to ensure that the radiological impact from releasing gaseous and particulate effluents from the Unit 1 containment equipment hatch to the environment was properly assessed prior to the release, and the release was properly quantified and reported. The licensee conservatively reconstructed the effluent concentrations and projected dose to the public, and entered the event into the corrective action program.

The finding was more than minor because the issue was associated with the Public Radiation Safety cornerstone attribute of program and process and potentially affected the cornerstone objective to ensure adequate protection of the public from exposure to radioactive materials from the release of gaseous effluents. The finding was determined to be of very low safety significance, because the issue was not associated with radioactive material control, and although there was an impaired ability to access dose prior to the releases, the licensee's dose assessment demonstrated that the actual effluent releases were calculated to be within regulatory dose limits and ALARA dose constraints. Since the principal cause of the problem was a problem identification and resolution deficiency, the finding also relates to the cross-cutting area of problem identification and resolution. (Section 2PS1)

B. <u>Licensee-Identified Violations</u>

Violations of very low safety significance, which were identified by the licensee, have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. The violations and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at or near full power until April 14, 2006, when operators initiated a manual reactor trip after a failure of the 11 condensate pump which resulted in the loss of the 11 main feedwater pump. The reactor was restarted and the generator placed online on April 16, 2006. The unit operated at or near full power until April 28, 2006, when the unit was shut down for refueling outage 1R24. Unit 1 was made critical on June 5, 2006, the generator was placed online on June 6, 2006, and the unit was gradually brought to full power over the next few days. The unit operated at or near full power until June 11, 2006, when power was reduced to approximately 60 percent to perform post-maintenance testing following the replacement of a bearing on the 11 turbine-driven auxiliary feedwater (AFW) pump turbine. The unit operated at or near full power for the remainder of the inspection period.

Unit 2 operated at or near full power throughout the inspection period except when power was reduced to approximately 48 percent on April 9, 2006, for approximately 22 hours for maintenance on the 22 feedwater pump and turbine valve testing.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Protection Against Tornados and High Velocity Winds

a. Inspection Scope

On May 2, 2006, the inspectors completed a detailed in-office review of the licensee's procedures and an in-plant walkdown of four systems to observe the licensee's preparations for adverse weather conditions that could result from nearby tornados or high wind conditions. The inspectors performed a detailed review of the tornado and high winds hazard procedures; the Updated Safety Analysis Report (USAR); design basis documents for the Unit 1 and Unit 2 switchyard; and the Prairie Island Individual Plant Examination of External Events (IPEEE). The inspectors verified that required surveillance tests were scheduled and performed at the specified frequencies. During system walkdowns, the inspectors examined the material condition of major system components for evidence of system degradation. As part of this inspection, the documents in the Attachment were utilized to evaluate the potential for an inspection finding.

The inspectors evaluated readiness for seasonal susceptibilities for the following systems, completing one inspection procedure sample:

- the Unit 1 diesel generators D1and D2;
- the plant substation system;
- the cooling tower substation system including transformers CT-11 and CT-12;

- auxiliary and standby transformer system; and
- Unit 1 containment during periods when the containment hatch was removed.

b. Findings

No findings of significance were identified.

.2 Hot Weather Preparations

a. Inspection Scope

On June 16 through 20, 2006, the inspectors performed an in-office review of the summer plant operation program; the USAR; applicable Technical Specifications (TS); and the Prairie Island IPEEE. This inspection effort completed the hot weather preparation inspection sample. The inspectors performed in-plant walkdowns of selected systems and verified that the as-found conditions of those systems were consistent with the description provided in the above documents. The inspectors performed in-plant walkdowns of the following risk-significant mitigating system support systems for a total of one inspection sample:

- diesel generator D1 and D2 ventilation system;
- diesel generator D5 and D6 ventilation system; and
- instrument and service air system.

The inspectors reviewed the selected systems and verified that the material conditions and system configurations supported the systems' availability and operability under adverse hot weather conditions, and verified that additional cooling equipment, where specified in the summer plant operation procedure, was available and operable.

The inspectors also reviewed the correction action programs action requests (CAPs) listed in the Attachment to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures.

b. Findings

No findings of significance were identified.

1R02 Evaluation of Changes, Tests, or Experiments (71111.02)

Reactor Vessel Head Replacement Inspection (71007)

a. Inspection Scope

From April 24 through 28, 2006, from May 1 through 5, 2006, and from May 15 through 19, 2006, the inspectors reviewed the licensee's evaluations of applicability determination and screening questions for the design changes associated with the Unit 1 reactor vessel closure head (RVCH) replacement to determine, for each change, whether the requirements of 10 CFR 50.59 had been appropriately applied. Screenings and evaluations reviewed for the Unit 2 RVCH replacement (refer to IR 05000282/2005004; 05000306/2005004 (ML052020420)) that were also applicable to the Unit 1 RVCH replacement were not reviewed as part of this inspection. Specifically, the inspectors reviewed Part 1 of Design Change 03RV05, "Replace Unit 1 and 2 Reactor Vessel Heads and Associated Components," which included a review of the function of each changed component, the change description and scope of three 10 CFR 50.59 screenings for the:

- reactor vessel head internal insulation;
- reactor coolant gas vent system (RCGVS) and reactor vessel level indication system (RVLIS) pipe and supports; and
- abandonment of upper range RVLIS indication.

The inspectors also reviewed three 10 CFR 50.59 screenings and one 10 CFR 50.59 evaluation associated with the Unit 1 head assembly upgrade package (HAUP) to determine, for each change, whether the requirements of 10 CFR 50.59 had been appropriately applied. Screenings reviewed for the Unit 2 HAUP installation (refer to IR 05000282/2005004; 05000306/2005004 (ML052020420)), that were also applicable to the Unit 1 HAUP installation, were not reviewed as part of this inspection. Specifically, the inspectors reviewed Part 2 of Design Change 03RV05, "Reactor Vessel Head Assembly Upgrade Package (HAUP)," which included a review of the function of each changed component, the change description, methods of analysis, and scope of the 10 CFR 50.59 screenings and the 10 CFR 50.59 evaluation for the:

- reactor vessel control rod drive mechanism (CRDM) seismic platform, seismic spacer plate, adjustment plate assembly, cable supports;
- CRDM cooling: coils, fans, pipe/pipe supports, and instrumentation and control;
- evaluation of non-safety-related components for loss of coolant accident (LOCA) loads; and
- heavy loads licensing bases.

The inspectors used, in part, Nuclear Energy Institute (NEI) 96-07, "Guidelines for 10 CFR 50.59 Implementation," to determine acceptability of the completed pre-screenings and screening. The NEI document was endorsed by the NRC in Regulatory Guide 1.187, "Guidance for Implementation of 10 CFR 50.59, Changes, Tests, and Experiments." The inspectors also consulted Part 9900 of the NRC Inspection Manual, "10 CFR Guidance for 10 CFR 50.59, Changes, Tests, and Experiments."

The records reviewed by the inspectors are identified in the Attachment to this report.

b. <u>Findings</u>

<u>USAR Change that Removed the Reactor Vessel Head Lift Elevation Limit and Reference to the Associated Reactor Vessel Head Load Drop Calculation</u>

<u>Introduction</u>: On April 19, 2006, the inspectors identified a Severity Level IV Non-Cited Violation (NCV) of very low safety significance (Green) for failing to perform an adequate safety evaluation in accordance with 10 CFR 50.59. Safety Evaluation 1052,

Revision 0, "Heavy Load Licensing Bases," involved a USAR change that removed the maximum reactor vessel head lift elevation restriction, and reference to the associated reactor vessel head load drop calculation that provided the design basis for the lift elevation limit. Within the safety evaluation, the licensee failed to provide a basis for why the removal of this lift elevation restriction from the USAR did not present more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system, or component (SSC) important to safety if the reactor vessel head was dropped at an elevation higher than that evaluated in the load drop calculation with irradiated fuel in the reactor core.

Description: The licensee initiated 10 CFR 50.59 Safety Evaluation 1052 to support a revision to the USAR that removed the maximum reactor vessel head lift elevation restriction and reference to the associated reactor vessel head load drop calculation that provided the design basis for the lift elevation limit. As indicated in Safety Evaluation 1052, the NRC required licensees to determine the extent that guidelines in NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," were satisfied and to identify changes and modifications that would be required to satisfy those guidelines (NRC Letter dated December 22, 1980, Subject: Control of Heavy Loads (GL 80-113); NRC Generic Letter (GL) 81-07; dated February 3, 1981, Control of Heavy Loads). The licensee responses were in two phases, Phase I and Phase II:

> Prairie Island Nuclear Generating Plant (PINGP) submitted their Phase I report to the NRC, on August 31, 1981, with additional information provided in subsequent letters. NRC Safety Evaluation Report dated June 6, 1983, concluded that PINGP satisfactorily complied with the Phase I requirements.
>
> For the Phase II response, the NRC requested that licensees submit information on overhead cranes in the vicinity of spent fuel pools, in containment, and in plant areas containing equipment required for reactor shutdown, core decay heat removal, or spent fuel pool cooling (NUREG-0612 Sections 5.1.2, 5.1.3, and 5.1.5). With respect to the containment polar crane, NUREG-0612 Section 5.1.3 required a single-failure proof crane, or as an alternative, analysis could be performed demonstrating that evaluation criteria listed in NUREG-012 Section 5.1 were satisfied.
>
> As part of their Phase II submittal (NSP Letter, dated December 9, 1981, Control of Heavy Loads (9 Month Submittal)), PINGP outlined compliance with NUREG-0612 Guideline 5.1.3. This included a reactor head drop analysis that concluded both 4-inch diameter safety injection (SI) lines (reactor vessel injection) would remain functional, and thus, the capability was maintained to provide borated water to the reactor vessel to make up for any water due to boiling. This satisfied Criterion III of Section 5.1 of NUREG-0612. On May 31, 1984, the NRC provided PINGP with a draft Technical Evaluation Report (TER) related to the Phase II submittal. The draft TER concluded that the information provided by PINGP indicates that Criterion III (uncovering of the core) have been satisfied in a manner consistent with the intent of NUREG-0612. No outstanding issues were identified in the draft TER related to the reactor head drop analysis. However, the NRC did not issue an official Safety Evaluation Report for the PINGP Phase II submittal.

In Safety Evaluation 1052, the licensee concluded that actions provided in their Phase I submittal were part of their licensing basis, but actions provided to the NRC in their Phase II submittal were not part of their licensing basis based on GL 85-11, "Clarification of Response to the Heavy Loads Phase II Technical Evaluation Report," and NUREG-1774, "Survey of Crane operating Experience at US Nuclear Power Plants from 1968 through 2002." The licensee also concluded that GL 85-11 relieved licensees from performing the actions requested under Phase II and rescinded the requirement to perform a Phase II review requested in GL 80-113 and GL 81-07. Safety Evaluation 1052 further concluded that maintaining an analysis of a postulated drop of the reactor vessel head was neither a regulatory requirement nor a licensing commitment for PINGP. As a result, the licensee revised the USAR to remove the maximum reactor vessel head lift elevation restriction and reference to the associated reactor vessel head load drop calculation that provided the design basis for the lift elevation limit.

The inspectors reviewed NRC Regulatory Issue Summary (RIS) 2005-25, "Clarification of NRC Guidelines for Control of Heavy Loads," dated October 31, 2005. Clarifications and related information provided by RIS 2005-25 include:

- In GL 85-11, the NRC staff concluded that a detailed review (NRC detailed review) of the Phase II responses received by the licensee was not necessary based on an NRC staff pilot review of Phase II responses. Although, the NRC staff concluded that the cost to install a single-failure-proof crane was not justified on a generic basis, the NRC staff encouraged licensees to determine and implement appropriate actions to provide adequate safety. In GL 85-11, the NRC staff did not relieve licensees from performing the actions requested under Phase II nor rescind the requirement to perform a Phase II review.

- Phase II guidelines addressed alternatives to reduce the consequences of heavy load drops. One option was to perform a load drop and consequence analysis to assess the impact of dropped loads on plant safety and operations.

- The NRC Advisory Committee on Reactor Safeguards, in a letter dated September 24, 2003, (ML032681205) endorsed the recommendation to evaluate the need to establish standardized calculation methodologies for heavy load drops. As noted in RIS 2005-25, Enclosure 1, PINGP revised their load drop analysis due to assumptions and methodology that were determined to be non-conservative and reduced the maximum reactor vessel head lift elevation indicated in the USAR (refer to IR 05000282/2005004; 05000306/2005004 (ML052020420)).

The inspectors determined that based on RIS 2005-25 clarifications, the PINGP load drop analysis was part of the design basis that determined SSCs important to safety, the 4-inch SI lines, would remain functional after a postulated load drop. Although the USAR had been changed to remove the reactor vessel head lift elevation limit and the reference to the associated reactor vessel head load drop calculation, the reactor vessel head lift elevation limit established by the reactor vessel head load drop analysis was still controlled by the licensee in maintenance procedures.

The inspectors determined that the 10 CFR 50.59 evaluation that was performed to remove the reactor vessel head lift elevation limit and the reference to the associated reactor vessel head load drop calculation from the USAR was not in accordance with the requirements in 10 CFR 50.59. Specifically, the evaluation did not adequately address the likelihood of occurrence of a malfunction of an SSC important to safety, the 4-inch SI lines, if the reactor vessel head was dropped at an elevation higher than that evaluated in the load drop calculation with irradiated fuel in the reactor core. The inspectors noted that this change to the USAR may have resulted in more than a minimal increase in the likelihood of occurrence of a malfunction of an SSC important to safety, since the reactor vessel had sufficient energy-absorbing capacity at a maximum lift elevation determined by the load drop analysis (Calculation 2005-05621). The licensee entered this condition into their corrective action program as CAPs 0125009 and 01030355. As a result, the licensee performed a revision to Safety Evaluation 1052 and reinstated into the USAR the reactor vessel head lift elevation limit and the reference to the reactor vessel head load drop analysis (Calculation 2005-05621).

<u>Analysis</u>: The inspectors determined that the removal of the head lift elevation limit from the USAR was a performance deficiency, since the licensee permanently changed the facility as described in the USAR without providing the necessary justification under 10 CFR 50.59 for the activity that created a possibility for a malfunction of an SSC important to safety with a different result than previously evaluated in the USAR. The finding was determined to be more than minor, because the inspectors could not reasonably determine that the USAR change, which adversely affected equipment important to safety, would not have required NRC approval.

Because violations of 10 CFR 50.59 are considered to be violations that potentially impede or impact the regulatory process, they are dispositioned using the traditional enforcement process instead of the Significance Determination Process (SDP). However, if possible, the underlying technical issue is evaluated under the SDP to determine the severity of the violation. In this case, the finding screened as having very low safety significance (Green) using Inspection Manual Chapter (IMC) 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for the At-Power Situations," because the inspectors answered "no" to question 1 under the Mitigating Systems Cornerstone column of the Phase 1 worksheet. Specifically, the licensee had not performed a reactor vessel head lift where the lift height was in excess of the elevation evaluated in their load drop analysis, and licensee maintenance procedures limited the maximum allowed reactor vessel head lift height to be less than the elevation evaluated in their load drop analysis. Based upon this Phase 1 screening, the inspectors concluded that the issue was of very low safety significance (Green). In accordance with the Enforcement Policy, the violation was therefore classified as a Severity Level IV violation.

<u>Enforcement</u>: Title 10 CFR 50.59(d)(1) states, in part, that the licensee shall maintain records of changes in the facility, of changes in procedures, and of tests and experiments. These records must include a written evaluation which provides a basis for the determination that the change, test, or experiment does not require a license amendment.

Contrary to the above, in Safety Evaluation 1052, Revision 0, the licensee failed to provide an adequate basis for the determination that removal of the maximum reactor vessel head lift elevation restriction and reference to the associated reactor vessel head load drop calculation from the USAR was acceptable without a license amendment. Specifically, the change in the USAR coupled with conclusion of Safety Evaluation 1052 that the reactor vessel head load drop analysis was neither a regulatory requirement nor a licensing commitment may have resulted in removal of the reactor vessel head lift elevation restriction from maintenance procedures without determining the potential consequences of a postulated reactor vessel head load drop. Within the 10 CFR 50.59 evaluation, the licensee failed to provide a basis for why removal of the reactor vessel head lift elevation limit and reference to the associated reactor vessel head load drop calculation did not present more than a minimal increase in the likelihood of occurrence of a malfunction of an SSC important to safety if the reactor vessel head was dropped at an elevation higher than that evaluated in the load drop calculation with irradiated fuel in the reactor core. In accordance with the Enforcement Policy, this violation of the requirements of 10 CFR 50.59 was classified as a Severity Level IV Violation because the underlying technical issue was of very low safety significance. Because this non-willful violation was non-repetitive, and was captured in the licensee's corrective action program (CAP 01030355), it is considered an NCV consistent with VI.A.1 of the NRC Enforcement Policy. (NCV 05000282/2006003-01; 05000306/2006003-01).

1R04 Equipment Alignment (71111.04)

.1 Partial Walkdowns

a. Inspection Scope

The inspectors performed three partial system equipment alignment inspection samples comprised of in-plant walkdowns of accessible portions of trains of risk-significant equipment associated with the mitigating systems and barrier integrity cornerstones. The inspectors conducted the inspections during times when the trains were of increased importance due to the redundant trains or other related equipment being unavailable. The inspectors also reviewed documents entering deficient conditions associated with equipment alignment issues into the corrective action program verifying that the licensee was identifying issues at an appropriate threshold and entering those issues into their corrective action program in accordance with the fleet corrective action procedures.

The inspectors utilized the valve and electric breaker checklists, where applicable, to verify that the components were properly positioned and that support systems were lined up as needed. The inspectors also examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious performance deficiencies. The inspectors reviewed outstanding work orders (WOs) and CAPs associated with the operable trains to verify that those documents did not reveal issues that could affect the completion of the available train's safety functions. The inspectors used the information in the appropriate sections of the USAR to determine the functional requirements of the systems.

The inspectors verified the alignment of the following trains:

- D1 diesel generator during the unavailability of the D2 diesel generator for planned maintenance on April 12, 2006;
- 12 motor-driven AFW pump during the unavailability of the 11 turbine-driven AFW pump on June 14, 2006; and
- D6 diesel generator during the unavailability of the D5 diesel generator for planned maintenance on June 19, 2006.

Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R05 Fire Protection Area Walkdowns (71111.05)

a. Inspection Scope

The inspectors conducted in-office and in-plant reviews of portions of the licensee's Fire Hazards Analysis and Fire Strategies to verify consistency between these documents and the as-found configuration of the installed fire protection equipment and features in the fire protection areas listed below. The inspectors selected fire areas for inspection based on their overall contribution to internal fire risk as documented in the IPEEE, their potential to impact equipment that could initiate a plant transient, or their impact on the plant's ability to respond to a security event. The inspectors assessed the control of transient combustibles and ignition sources, the material and operational condition of fire protection systems and equipment, and the status of fire barriers. In addition, the inspectors reviewed CAPs associated with fire protection issues to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with fleet corrective action procedures.

The following nine fire areas were inspected by in-plant walkdowns supporting the completion of nine fire protection zone walkdown samples:

- Fire Area 18, Relay and Cable Spreading Room, on April 7, 2006;
- Fire Area 20, Bus 15 and 16 Switchgear Rooms, on April 7, 2006;
- Fire Areas 102, D5/D6 Building, on April 10, 2006;
- Fire Areas 106, D5/D6 Building, on April 10, 2006;
- Fire Areas 114, D5/D6 Building, on April 10, 2006;
- Fire Areas 118, D5/D6 Building, on April 10, 2006;
- Fire Areas 122, D5/D6 Building, on April 10, 2006;
- Fire Area 68, Unit 1 Annulus, on May 4, 2006; and
- Fire Area 1, Unit 1 Reactor Building, on May 6, 2006.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

On May 4, 2006, the inspectors performed an in-plant walkdown of the Unit 1 and 2 safety-related cooling water pump and containment spray pump rooms completing one internal flood protection inspection sample. These areas of Unit 1 and 2 contain safety-related and risk-significant equipment including both safety-related trains of cooling water pumps, the Unit 1and 2 safety-related containment spray pumps, and flood seals for piping penetrations between the containment spray and residual heat removal (RHR) pump rooms. The inspectors reviewed the applicable sections of the USAR, Individual Plant Examination, and plant procedures associated with internal flooding of the before mentioned pump rooms and adjacent areas. The inspectors verified by in-plant inspection that the licensee maintained the material condition of piping systems in these areas. The inspectors also verified that drain paths from these areas had been maintained and that there was no accumulation of loose materials that could plug drain paths.

The inspectors reviewed a CAP to verify that problems associated with plant equipment relied upon to prevent or minimize flooding were identified at an appropriate threshold, and that corrective actions commensurate with the significance of the issue were identified and implemented. The documents reviewed by the inspectors are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope

The inspectors observed the licensee's performance during the annual zebra mussel control treatment between April 19 and April 21, 2006, to verify the performance of the treatment and the monitoring of critical operating parameters following the application of the treatment.

This inspection constituted one inspection sample. The key documents reviewed by the inspectors associated with this inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

.1 Inspection Activities

The inspectors conducted an assessment of the effectiveness of the licensee's inservice inspection (ISI) program for monitoring degradation of vital system boundaries including the Unit 1 reactor coolant system (RCS) and risk-significant piping systems. Specifically, the inspectors conducted an onsite review of the following nondestructive examination activities performed during the Unit 1 1R24 outage to evaluate compliance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code requirements and to verify that indications and defects were dispositioned in accordance with the ASME Code:

- ultrasonic examination of safety injection pipe-elbow weld 30;
- magnetic particle examination of feedwater seismic restraint H-28; and
- visual examination of 4 lugs (H-4) on a hydraulic snubber for the reactor coolant RHR system (RCRH-53).

The inspectors also reviewed the following examination from the previous outage with recordable indications that have been accepted by the licensee for continued service to verify that the licensee's acceptance for continued service was in accordance with the ASME Code:

- liquid penetrant examination of a chemical and volume control system H-3/1A anchor support welds (linear indications found on welds A and D).

The inspectors reviewed the following pressure boundary welds for a Unit 2 ASME Code Class 1 system to verify that the welding process and welding examinations were performed in accordance with ASME Code requirements:

- radiographic examination of a pressurizer power operated relief valve (PORV) pipe to valve (MV-32198) weld, Weld 1;
- radiographic examination of a pressurizer PORV valve (MV-32198) to pipe weld, Weld 2; and
- WO package 0406806, replacement of pressurizer PORV (MV-32198).

The reviews as discussed above counted as one inspection sample.

b. Findings

No findings of significance were identified.

.2 Pressurized Water Reactor Vessel Upper Head Penetration Inspection Activities

The inspectors were unable to review Unit 1 upper head penetration inspection activities because none were performed. Instead, the licensee replaced the upper head this outage.

Because this was not available for inspection, this was not counted as a completed inspection sample.

.3 Boric Acid Corrosion Control Inspection Activities

a. Inspection Scope

On April 29, 2006, through May 11, 2006, the inspectors reviewed the Unit 1 Boric Acid Corrosion Control (BACC) inspection activities conducted pursuant to licensee commitments made in response to NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary." Plant engineers commenced an examination of the reactor coolant and the other borated systems on April 29, 2006, while the reactor was in Mode 3 and reactor coolant system was at pressure, to evaluate compliance with licensee BACC program requirements. The inspectors observed the licensee during the performance of BACC visual examinations conducted in accordance with Surveillance Procedure (SP) 1405. Specifically, the inspectors observed these examinations to determine if the licensee focused on locations where boric acid leaks can cause degradation of safety significant components.

Additionally, the inspectors independently identified three reactor coolant system valves with minor boric acid leakage. The inspectors verified that the licensee had also identified the condition of the three valves as degraded or non-conforming and entered those conditions into their corrective action program in accordance with the licensee's corrective action program procedure and 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements.

The inspectors reviewed engineering evaluations performed for a boric acid packing leak found on the 11 RHR heat exchanger outlet valve (RH-10-2) to verify that the minimum design code required section thickness had been maintained for the affected component(s). Specifically, the inspectors reviewed:

- Operability Recommendation CAP 042581.

The inspectors reviewed licensee corrective actions implemented for evidence of boric acid leakage to confirm that they were consistent with requirements of Section XI of the ASME Code and 10 CFR Part 50, Appendix B, Criterion XVI.

The documents reviewed during this inspection are listed in the Attachment to this report.

The reviews, as discussed above, counted as one inspection sample.

b. Findings

No findings of significance were identified.

.4 Unit 1 Steam Generator (SG) Tube Inspection Activities

a. Inspection Scope

This was the first refueling outage (U1R24) since the 2004 (U1R23) SG replacement with thermally treated Alloy 690 tubes. The minimum inspection requirement was therefore used as reflected in the procedure steps inspected below.

The NRC inspectors observed acquisition of eddy current (ET) data, interviewed ET data analysts, and reviewed a sample of documents related to the SG ISI program to determine if:

- Procedure 71111.08, Step 02.04.a.1 and Step 02.04.a.2, the in-situ screening criteria, were in accordance with the Electric Power Research Institute (EPRI) guidelines and the appropriate tubes were to be in-situ pressure tested;
- Procedure 71111.08, Step 02.04.c, the SG tube ET examination scope and expansion criteria were sufficient to identify tube degradation based onsite and industry operating experience by confirming that the ET scope completed was consistent with the licensee's procedures, plant TS requirements and EPRI 1003138, "Pressurized Water Reactor Steam Generator Examination Guidelines," Revision 6;
- Procedure 71111.08, Step 02.04.g.(1), the TS plugging limit is being adhered to;
- Procedure 71111.08, Step 02.04.I, the ET probes and equipment configurations used to acquire data from the SG tubes were qualified to detect the known/expected types of SG tube degradation in accordance with Appendix H, "Performance Demonstration for Eddy Current Examination," of EPRI 1003138, "Pressurized Water Reactor Steam Generator Examination Guidelines," Revision 6; and
- Procedure 71111.08, Step 02.04.j, the licensee performed evaluations for unretrievable loose parts.

Activities which were not applicable during this inspection are as follows:

- Procedure 71111.08, Steps 02.04.a.3 and 02.04.a.4, In-situ Pressure Testing, were not available for review, because none of the SG tubes examined during the current refueling outage met the screening requirements for pressure testing;
- Procedure 71111.08, Step 02.04.d, new tube degradation mechanisms were not available for review because none were present; and
- Procedure 71111.08, Step 02.04.h, the primary-to-secondary leakage, (e.g., SG tube leakage) was not available for review, because primary-to-secondary leakage did not exceed 3 gallons per day during operations or during post-shutdown visuals.

The reviews, as discussed above, counted as one inspection sample.

b. Findings

No findings of significance were identified.

.5 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed a sample of ISI/SG related problems documented in the licensee's corrective action program to assess conformance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. The corrective action documents reviewed by the inspectors are listed in the Attachment to this report. In addition, the inspectors verified that the licensee correctly assessed operating experience for applicability to the Inservice Inspection Group.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On April 17, 2006, the inspectors performed a quarterly review of licensed operator requalification training in the simulator, completing one licensed operator requalification inspection sample. The inspectors observed a crew during an evaluated exercise in the plant's simulator facility. The inspectors compared crew performance to licensee management expectations. The inspectors verified that the crew completed all of the critical tasks for each exercise scenario. For any weaknesses identified, the inspectors observed that the licensee evaluators noted the weaknesses and discussed them in the critique at the end of the session.

The inspectors assessed the licensee's effectiveness in evaluating the requalification program ensuring that licensed individuals would operate the facility safely and within the conditions of their licenses, and evaluated licensed operators' mastery of high-risk operator actions. The inspection activities included, but were not limited to, a review of high-risk activities, emergency plan performance, incorporation of lessons learned, clarity and formality of communications, task prioritization, timeliness of actions, alarm response actions, control board operations, procedural adequacy and implementation, supervisory oversight, group dynamics, interpretations of TS, simulator fidelity, and licensee critique of performance.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed repetitive maintenance activities to assess maintenance effectiveness, including maintenance rule (10 CFR 50.65) activities, work practices, and common cause issues. The inspectors performed one issue/problem-oriented maintenance effectiveness sample. The inspectors assessed the licensee's maintenance effectiveness associated with problems on the station and instrument air system.

The inspectors conducted in-office reviews of the licensee's maintenance rule evaluations of equipment failures for maintenance preventable functional failures and equipment unavailability time calculations, comparing the licensee's evaluation conclusions to applicable Maintenance Rule (a)1 performance criteria. Additionally, the inspectors reviewed scoping, goal-setting (where applicable), performance monitoring, short-term and long-term corrective actions, functional failure definitions, and current equipment performance status.

The inspectors reviewed CAPs for significant equipment failures associated with risk-significant and safety-related mitigating equipment to ensure that those failures were properly identified, classified, and corrected. The inspectors reviewed other CAPs to assess the licensee's problem identification threshold for degraded conditions, the appropriateness of specified corrective actions, and that the timeliness of the implementation of corrective actions were commensurate with the safety significance of the identified issues. Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

a. Inspection Scope

The inspectors conducted in-plant walkdowns and in-office reviews of risk assessments for five planned maintenance activities and four maintenance activities that involved emergent equipment failures with the following combinations of equipment unavailability completing nine risk assessment and emergent work control inspection samples:

- the emergent unavailability of the Unit 2 volume control tank level transmitter concurrent with the planned unavailability of the 122 instrument air compressor on April 5, 2006;
- the emergent unavailability of the Unit 2 red channel reactor coolant flow instrument 2FI-411 concurrent with the planned unavailability of the 23 charging pump and the 122 instrument air compressor on April 13, 2006;
- the planned unavailability of the 11 RHR pump and the 11 condensate pump on April 24, 2006;
- the planned unavailability of the 11 safety injection pump, 121 instrument air compressor, and the 11 condensate pump on April 28, 2006;
- the planned unavailability of diesel generator D2 and the 480 volt electrical load transfers from bus 16 to bus 26 on May 5, 2006;
- the planned unavailability of diesel generator D2, 11 cooling water pump, bus 16, and the 12 AFW pump on May 8, 2006;

- the emergent unavailability of the 121 instrument air compressor concurrent with the planned unavailability of diesel generator D2, 11 cooling water pump, bus 16, and the 12 AFW pump on May 9, 2006;
- the emergent unavailability of the 11 turbine-driven AFW pump concurrent with the planned unavailability of the 122 instrument air compressor on June 15, 2006; and
- the planned unavailability of the 11 charging pump and the 11 RHR heat exchanger outlet to the 11 containment spray pump valve MV-32096 on June 28, 2006.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance Related to Non-Routine Plant Evolutions and Events (71111.14)

Operator Performance Following a Loss of the 11 Condensate Pump and Resulting Unit 1 Reactor Trip

a. Inspection Scope

On April 14, 2006, the 11 condensate pump tripped due to an electrical fault. The trip caused a lockout and trip of the 11 main feedwater pump, which resulted in declining steam generator levels. The operators initiated a manual reactor trip. The inspectors' review of the operator's response to the trip counted as one inspection sample for personnel performance to non-routine plant event.

The inspectors observed the performance of operations personnel in the control room following the unplanned and non-routine evolution, comparing their response to the actions specified in the applicable plant procedures. The inspectors also reviewed selected plant parameters to ensure the plant responded as designed. The documents reviewed by the inspectors are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the technical adequacy of five operability evaluations completing five operability evaluation inspection samples. The inspectors conducted these inspections by in-office review of associated documents and in-plant walkdowns of affected areas and plant equipment.

The inspectors compared degraded or nonconforming conditions of risk-significant SSCs associated with barrier and mitigating systems and against the functional requirements described in the TS, USAR, and other design basis documents; determined whether compensatory measures, if needed, were implemented; and determined whether the evaluation was consistent with the requirements of Administrative Work Instruction 5AWI 3.15.5, “Operability Determinations.” The following operability evaluations were reviewed by inspectors:

- prompt and historical operability determinations contained in CAP 01011542 for loose material found in Unit 1 RHR pump pit flood drainage path on May 8, 2006;
- Operability Recommendation (OPR) 01029449 that documented the operability of 4 kilovolt switchgear with non-safety-related parts used in safety-related applications on May 15, 2006;
- OPR 000531 that documented a missed inservice test on the Unit 1 volume control tank relief valve, VC-24-1, on May 30, 2006;
- OPR 01033009 that documented the operability of Unit 1 feedwater piping with discrepancies on pipe support 1-FWH-35, restraints 2 and 10, on May 31, 2006; and
- OPR 01034749 that documented the operability of the 11 turbine-driven AFW pump with higher than normal turbine outboard bearing temperature, on June 6, 2006.

The documents reviewed by the inspectors are listed in the Attachment to this report.

b. <u>Findings</u>

No findings of significance were identified.

1R19 <u>Post-Maintenance Testing</u> (71111.19)

a. <u>Inspection Scope</u>

The inspectors assessed post-maintenance testing completing six post-maintenance test inspection samples. The inspectors selected post-maintenance tests associated with important mitigating and barrier integrity systems to ensure that the testing was performed adequately, demonstrated that the maintenance was successful, and that operability of associated equipment and/or systems was restored. The inspectors conducted these inspections by in-office review of documents and in-plant walkdowns of associated plant equipment. The inspectors observed and assessed the post-maintenance testing activities for the following maintenance activities:

- diesel generator D2 cylinder liner replacement on May 15, 2006;
- replacement of the inlet check valve on the back up air supply accumulator for CV-31998, 11 turbine-driven AFW pump steam supply control valve on May 31, 2006;
- repacking of 11 turbine-driven AFW pump valves AF-13-3, pump discharge valve and CV-31998, main steam supply control valve, on June 2, 2006;
- CV-31235, 11 RHR heat exchanger reactor coolant outlet following repair of a boric acid leak on the valve, on June 2, 2006;
- replacement of 1N36, intermediate range nuclear instrument, high voltage and compensating voltage cables on June 5, 2006; and

- 11 turbine-driven AFW pump following replacement of a turbine bearing on June 11, 2006.

The inspectors reviewed the appropriate sections of the TS, USAR, and maintenance documents to determine the systems' safety functions and the scope of the maintenance. The inspectors also reviewed CAPs to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with fleet corrective action procedures. Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

.1 Condensate Pump Trip Forced Outage

a. Inspection Scope

A manual reactor trip on Unit 1 was performed on April 14, 2006, due to the trip of a main feedwater pump. The feedwater pump tripped due to an electrical fault on a condensate pump motor cable. The inspectors observed post-trip plant conditions to verify that plant parameters were within expected normal ranges. The inspectors observed the control room activities during reactor start up and synchronization of the generator to the grid on April 16, 2006.

b. Findings

No findings of significance were identified.

.2 Refueling and Reactor Head Replacement Outage (1R24)

a. Inspection Scope

The inspectors observed the licensee's performance during the twenty-fourth Unit 1 refueling outage (1R24) conducted between April 28, 2006, and June 06, 2006. These inspection activities represent one refueling outage inspection sample.

This inspection consisted of an in-office review of the licensee's outage schedule, safe shutdown plan and procedures governing the outage. Specifically, the inspectors assessed whether the licensee planned to effectively manage elements of shutdown risk pertaining to reactivity control, decay heat removal, inventory control, electrical power availability, and containment integrity. Additionally, the inspectors reviewed selected issues that the licensee entered into its corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance.

The inspectors conducted in-plant observations of the following outage activities daily:

- attended outage management turnover meetings to verify that the current shutdown risk status was accurate, well understood, and adequately communicated;
- performed walkdowns of the main control room to observe the alignment of systems important to shutdown risk;
- observed the operability of RCS instrumentation and compared channels and trains against one another;
- observed reduced inventory operations; and
- performed walkdowns to observe ongoing work activities and foreign material exclusion control.

Additionally, the inspectors performed in-plant observations of the following specific activities:

- Unit 1 shutdown and initial cooldown;
- alignment of the RHR system for shutdown cooling and control of reactor coolant system cooldown;
- reactor vessel head leakage examination per Inspection Procedure 71111.08, paragraph 02.03.b and SP 1407;
- reactor coolant system BACC inspection per Inspection Procedure 71111.08, paragraph 02.03.a and SP 1405;
- control room staff draining reactor level to the top of the hot legs;
- assessment of shutdown risk;
- core off load;
- core verification;
- inspected areas not accessible during at-power operation (Volume Control Tank room) to verify operable condition of equipment;
- replacement reactor vessel head lift and set;
- reactor coolant system heatup;
- reactor startup and initial critcality;
- physics testing; and
- generator online and power ascension.

Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

During this inspection period, the inspectors completed ten surveillance inspection samples. Observation of SPs 1088A and 1106C completed the quarterly inservice testing inspection requirement of a risk-significant pump or valve; SPs 1405 and 1070 completed two reactor coolant system leakage inspection requirements; SP 1405 also completed Inspection Procedure 71111.08, Section 02.03.a and 02.03.b inspection requirements; and SP 1072.45 completed the requirement to select a containment isolation valve each refueling cycle. The inspectors selected the following surveillance testing activities as samples:

- SP 2093, D5 Diesel Generator Monthly on April 21, 2006;
- SP 1405, Unit 1 Mid-Cycle and Refueling Outage Boric Acid Corrosion Examinations Inside Containment on April 28, 2006;
- SP 1088A, Train A Safety Injection Quarterly Test on April 28, 2006;
- SP 1092B and C, Safety Injection Check Valve Test, on May 5, 2006;
- SP 1126, Turbine Building Cooling Water Header Isolation Safety Injection Relays 1SI-12X and 1SI-22X Contact Verification Test on May 14, 2006;
- SP 1072.45, Local Leakage Rate Test of Penetration 45 (Reactor Water Makeup), on May 18, 2006;
- SP 1106C; 121 Cooling Water Pump Quarterly Test on May 25, 2006;
- SP 1083, Unit 1 Integrated Safety Injection Test with a Simulated Loss of Offsite Power, on May 27, 2006;
- SP 1750, Post-Outage Containment Closeout Inspection on June 1, 2006; and
- SP 1070, Reactor Coolant System Integrity Test on June 3, 2006.

During completion of the inspection samples, the inspectors observed in-plant activities and reviewed procedures and associated records to verify that:

- preconditioning did not occur;
- effects of the testing had been adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- acceptance criteria was clearly stated, demonstrated operational readiness, and was consistent with the system design basis;
- plant equipment calibration was correct, accurate, properly documented, and the calibration frequency was in accordance with TS, USAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy;
- applicable prerequisites described in the test procedures were satisfied;
- test frequency met TS requirements to demonstrate operability and reliability;
- the tests were performed in accordance with the test procedures and other applicable procedures;
- jumpers and lifted leads were controlled and restored where used;
- test data/results were accurate, complete, and valid;
- test equipment was removed after testing;
- where applicable for in-service testing activities, testing was performed in accordance with the applicable version of Section XI, ASME Code, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data have been accurately incorporated in the test procedure;

- equipment was returned to a position or status required to support the performance of its safety functions; and
- all problems identified during the testing were appropriately documented in the corrective action program.

Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors conducted in-plant observations of the physical changes to the equipment and an in-office review of documentation associated with one temporary modification completing one temporary modification inspection sample. The inspectors reviewed temporary modification 04T175 associated with a temporary installation of air bottles to supplement the air accumulator for each pressurizer PORV on May 24, 2006. The back up air bottles are required for the completion of the low temperature-overpressure protection function of the PORVs.

The inspection activities included a review of design documents, safety screening documents, and the USAR to determine that the temporary modification was consistent with modification documents, drawings, and procedures. The inspectors also reviewed the post-installation test results to confirm that tests were satisfactory and the actual impact of the temporary modification on the permanent system and interfacing systems were adequately verified. Additionally, the inspectors reviewed the corrective action documentation associated with an identified problem with the air supply to the PORVs to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action and has been listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed a licensed shift operating crew perform an “as-found” exercise on the simulator on April 20, 2006, completing one emergency planning simulator exercise sample. The inspectors observed activities in the control room simulator that include event classification and notification as well as the post-exercise critique. The inspectors evaluated the drill performance and verified that licensee evaluators’ observations were consistent with those of the inspectors, and that deficiencies were entered into the corrective action program. Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstones: Occupational Radiation and Public Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors reviewed licensee controls and surveys in the following two radiologically significant work areas in the plant and reviewed the work packages which included associated licensee controls and surveys of these areas to determine if radiological controls including surveys, postings, and barricades were acceptable:

- SI-9-2 check valve maintenance; and
- steam generator eddy current testing.

This review represented one inspection sample.

The inspectors reviewed the radiation work permits (RWPs) and work packages used to access these two areas and other high radiation work areas to identify the work control instructions and control barriers that had been specified. Electronic dosimeter alarm set points for both integrated dose and dose rate were evaluated for conformity with survey indications and plant policy. Workers were interviewed to verify that they were aware of the actions required when their electronic dosimeters noticeably malfunctioned or alarmed. This review represented one inspection sample.

The inspectors reviewed selected RWPs used in the containment on May 2, 2006, an airborne radioactivity area, to verify barrier integrity and engineering controls performance (e.g., High Efficiency Particulate Air (HEPA) ventilation system operation), and to determine if there was a potential for individual worker internal exposures of greater than 50 millirem committed effective dose equivalent.

Work areas having a history of, or the potential for, airborne transuranics were evaluated to verify that the licensee had considered the potential for transuranic isotopes and provided appropriate worker protection. Specifically, the inspectors reviewed the survey data available from breaching primary systems and surveys of the Reactor Pressure Vessel Head during the replacement process. This review represented one inspection sample.

The adequacy of the licensee's internal dose assessment process for internal exposures greater than 50 millirem committed effective dose equivalent was assessed. Additionally, the inspectors reviewed the licensee's assessment of 30 assigned internal exposures even though the exposures were less than 50 millirem. This review represented one inspection sample.

b. Findings

One finding of very low safety significance was identified. Additionally, a finding regarding airborne radioactivity areas in containment is discussed in Section 2OS2.2.

A High Radiation Area Barrier Found in an Open Position

Introduction: A Green finding and associated NCV were identified when NRC inspectors observed a High Radiation Areas (HRA) boundary barrier (a swing-gate) in the open position because it had moved in its base to the open position and would not swing closed.

Description: On May 10, 2006, while conducting a walkdown of Unit 1 containment, NRC inspectors observed a swing gate used as the entry barrier to an HRA located on the 695 level at the entrance to the 11 steam generator vault in the open position. The inspectors pulled the swing gate to the closed position but the gate immediately swung back to the open position because the gate post had rotated within its base, changing the orientation of gate closed position. The inspectors stayed at the entrance to the HRA to prevent unauthorized entry and sent one person to notify Radiation Protection personnel correct the problem. No personnel were inside the HRA at the time the compromised HRA barrier was identified.

The probability of unauthorized HRA entry was small while the swing gate (HRA barrier) was open, since the steam generator vault had video monitoring at the steam generator manway area, which was the most dose significant area within the HRA. It is anticipated that if workers had inadvertently entered the HRA they would have been detected by video monitoring. Additionally, a review of electronic dosimeter alarms did not identify any anomalies that would indicate that unauthorized individuals had entered this area. The licensee concluded that workers had previously entered/exited the HRA but failed to ensure that the swing gate barrier was properly positioned upon exit. The failure to assure through self-checking that the swing gate HRA barrier was closed when entering or leaving the HRA created a condition contrary to a TS that requires an HRA be barricaded and conspicuously posted as an HRA.

The licensee wrote a corrective action document (CAP 1029288) to initiate the problem identification and resolution process. The licensee conducted a review of containment HRA barriers to assure that no other HRA barriers/controls were at risk of failing. Additionally, the radiation protection staff was briefed on the finding during shift turnover meeting to heighten the awareness of the failure in an effort to prevent further occurrences.

On May 1 and 29, 2006, the licensee identified two additional incidents of similar HRA barrier failure, as described in Section 4OA7 of this report. As a result of these events and other HRA barrier and posting concerns identified during the outage the licensee initiated CAP 1033802 to assess an adverse trend in HRA control and take concerted corrective action to prevent recurrence.

Analysis: The failure to assure HRA barriers were returned to the closed position after use was a performance deficiency warranting a significance evaluation. The issue was associated with the Occupational Radiation Safety cornerstone and potentially affected the cornerstone objective to ensure adequate protection of worker health and safety from exposure to radiation. The issue was more than minor because it affected the Occupational Radiation Safety cornerstone attribute of program and process for radiation worker performance and consequently represented a finding as described in IMC 0612, Appendix B, "Issue Screening." The issue does not involve the application of traditional enforcement because it did not result in actual safety consequences or the potential to impact the NRC's regulatory function and was not the result of any willful actions. The finding was evaluated using IMC 0609, Appendix C, the SDP for the Occupational Radiation Safety cornerstone, and was determined to be of very low safety significance (Green) because it did not involve an As-Low-As-Reasonably-Achievable (ALARA) issue, as collective dose was not a factor and no individual received an unintended dose as a result of the barrier non-compliance. Additionally, individual radiation exposures for workers in and around this HRA of containment during that time was low relative to regulatory limits; there was not a substantial potential for a worker overexposure; and the licensee's ability to assess worker dose was not compromised. The inspectors determined that the performance deficiency associated with this event was a human performance failure in that radiation workers failed to use self-checking that led to a non-compliance with a TS. The primary cause of this event was a cross-cutting issue related to human performance.

As described in Section 4OA7, Licensee Identified Violations, two additional HRA barrier events were licensee-identified and had similar human performance weaknesses identified.

Enforcement: Technical Specification 5.7.1.a. requires for an HRA with dose rates less than 1.0 rem in 1 hour at 30 centimeters from the radiation source or from any surface that the radiation penetrates, each entryway to such an area shall be barricaded.

Contrary to the above, on May 10, 2006, a barricade to an HRA located on 695' level at the entrance to the 11 steam generator vault in the Unit 1 containment was left in the open position and was not attended by personnel to prevent unauthorized entry. Since the finding is of very low safety significance and had been entered into the corrective action system as CAP 1029288, the associated violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000282/2006003-02; 05000306/2006003-02).

.2 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed five corrective action reports related to access controls and four HRA radiological incidents (non-performance indicators identified by the licensee in high radiation areas less than 1 rem per hour). Staff members were interviewed and corrective action documents were reviewed to verify that follow-up activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk based on the following:

- initial problem identification, characterization, and tracking;
- disposition of operability/reportability issues;
- evaluation of safety significance/risk and priority for resolution;
- identification of repetitive problems;
- identification of contributing causes;
- identification and implementation of effective corrective actions;
- resolution of NCVs tracked in the corrective action system; and
- implementation/consideration of risk significant operational experience feedback.

This review represented one inspection sample.

b. Findings

No findings of significance were identified.

.3 Job-In-Progress Reviews

a. Inspection Scope

The inspectors observed the following two jobs that were being performed in radiation areas, airborne radioactivity areas, or high radiation areas for observation of work activities that presented the greatest radiological risk to workers:

- steam generator eddy current testing; and
- safety injection 92-2 check valve maintenance.

The inspectors reviewed radiological job requirements for these two activities including RWP requirements and work procedure requirements, and attended an ALARA job briefing. This review represented one inspection sample.

Job performance was observed with respect to these requirements to verify that radiological conditions in the work area were adequately communicated to workers through pre-job briefings and postings. The inspectors also verified the adequacy of radiological controls including required radiation, contamination, and airborne surveys for system breaches; radiation protection job coverage which included audio and visual surveillance for remote job coverage; and contamination controls. This review represented one inspection sample.

Radiological work in high radiation work areas having significant dose rate gradients was reviewed to evaluate the application of dosimetry to effectively monitor exposure to personnel and to verify that licensee controls were adequate. These work areas involved those where the dose rate gradients were severe, which increased the necessity of providing multiple dosimeters and/or enhanced job controls. This review represented one inspection sample.

b. Findings

No findings of significance were identified.

.4 High Risk Significant, High Dose Rate High Radiation Area, and Very High Radiation Area Controls

a. Inspection Scope

The inspectors held discussions with the radiation protection manager concerning high dose rate/high radiation area and very high radiation area controls and procedures, including procedural changes that had occurred since the last inspection, in order to verify that any procedure modifications did not substantially reduce the effectiveness and level of worker protection. This review represented one inspection sample.

The inspectors discussed with radiation protection supervisors the controls that were in place for special areas that had the potential to become very high radiation areas during certain plant operations, to determine if these plant operations required communication beforehand with the radiation protection group, so as to allow corresponding timely actions to properly post and control the radiation hazards. This review represented one inspection sample.

The inspectors conducted plant walkdowns to verify the posting and locking of entrances to high dose rate HRAs, and very high radiation. This review represented one inspection sample.

b. Findings

No findings of significance were identified

.5 Radiation Worker Performance

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation worker performance with respect to stated radiation protection work requirements and evaluated whether workers were aware of the significant radiological conditions in their workplace, the RWP controls and limits in place, and that their performance had accounted for the level of radiological hazards present. This review represented one inspection sample.

The inspectors reviewed radiological problem reports which found that the cause of the event was due to radiation worker errors to determine if there was an observable pattern traceable to a similar cause, and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. These problems, along with planned and taken corrective actions, were discussed with the radiation protection manager. This review represented one inspection sample.

b. <u>Findings</u>

No findings of significance were identified, other than those previously discussed in Section 2OS1.1.

.6 <u>Radiation Protection Technician Proficiency</u>

a. <u>Inspection Scope</u>

During job performance observations, the inspectors evaluated radiation protection technician performance with respect to radiation protection work requirements, and evaluated whether they were aware of the radiological conditions in their workplace, the RWP controls and limits in place, and if their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities. This review represented one inspection sample.

The inspectors reviewed one radiological problem report which found that the cause of the event was radiation protection technician error to determine if the corrective action approach taken by the licensee to resolve the reported problems was appropriate. This review represented one inspection sample.

b. <u>Findings</u>

No findings of significance were identified.

2OS2 <u>ALARA Planning and Controls</u> (71121.02)

.1 <u>Inspection Planning</u>

a. <u>Inspection Scope</u>

The inspectors reviewed plant collective exposure history, current exposure trends, and ongoing and planned activities in order to assess current performance and exposure challenges. This included determining the plant's current 3-year rolling average for collective exposure in order to help establish resource allocations and to provide a perspective of significance for any resulting inspection finding assessment. This review represented one inspection sample.

The inspectors reviewed the outage work scheduled during the inspection period and associated work activity exposure estimates for the following three work activities which were likely to result in the highest personnel collective exposures. These activities included:

- steam generator eddy current testing;
- safety injection 92-2 check valve maintenance; and
- steam generator manway removal.

This review represented one inspection sample.

The inspectors reviewed procedures associated with maintaining occupational exposures ALARA and processes used to estimate and track work activity specific exposures. This review represented one inspection sample.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning.

a. Inspection Scope

The inspectors evaluated the licensee's list of work activities ranked by estimated exposure that were in progress and reviewed the following four work activities of highest exposure significance:

- steam generator eddy current testing;
- steam generator 11 and 12 primary nozzle dam installation;
- safety injection 92-2 check valve maintenance; and
- steam generator manway removal.

This review represented one inspection sample.

For these four activities, the inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements in order to verify that the licensee had established procedures, and engineering and work controls that were based on sound radiation protection principles in order to achieve occupational exposures that were ALARA. This also involved determining that the licensee had reasonably grouped the radiological work into work activities, based on historical precedence, industry norms, and/or special circumstances. This review represented one inspection sample.

The inspectors compared the results achieved including dose rate reductions and person-rem used with the intended dose established in the licensee's ALARA planning for these four work activities. Reasons for inconsistencies between intended and actual work activity doses were reviewed. This review represented one inspection sample.

b. Findings

One finding of very low safety significance was identified.

ALARA Planning Does Not Identify and Prepare for Potential Airborne Conditions When Opening the Steam Generator Manways

Introduction: A self-revealed finding of very low safety significance and an associated NCV were identified when 110 radiation workers were contaminated when the steam generator manways were opened during the 1R24 refueling outage. Specific ALARA planning assessments for steam generator manway opening did not acknowledge that airborne concentrations of radioactivity may be subject to change. Additionally the ALARA planning for this work did not consider the effect of engineering safety systems such as HEPA filtration operation or malfunction on other work areas in containment. As a result, the containment clean-up filtration system was not properly aligned and secured to the HEPA exhaust to ensure proper control of radioactive iodine in the containment building atmosphere. Consequently, when the work area was set up and initial work commenced, the focus was on the immediate work area only and the result was elevated iodine-131 levels throughout containment.

Description: On May 2, 2006, workers opened the steam generator manways to prepare for nozzle dam installation and eddy current testing. A HEPA filtration system was installed in the steam generator vault to reduce particulate contamination from the primary system opening and reduce the potential for airborne conditions in the immediate work area. Additionally, this HEPA was connected to the manway opening to provide contamination control for the steam generator. Radiation workers and radiation protection technicians did not assure that the discharge from the HEPA systems were properly directed to the containment clean up filter, a HEPA/charcoal filtration train, designed to reduce particulate and gaseous contaminates. Specifically, the HEPA discharge hose was inadequately secured to the containment clean-up filter intake. To install the 11 steam generator manway HEPA discharge hose, workers used procedure 1D27.39, “Initial Steam Generator Outage Work Activities,” Attachment F, “Install HEPA Filter Units for 11 and 12 Steam Generators.” However, this procedure did not specify the proper method for attaching the HEPA discharge to the containment clean-up filter input or provide verification of proper fit-up and relied on workers’ judgment. When the HEPA discharge hose slipped off the containment clean-up filter intake, because it was loosely attached with wire tie wraps, the steam generator vented directly to the 755' of containment, and this led to increased iodine-131 levels throughout the containment building atmosphere necessitating an evacuation.

Inspectors reviewed the HEPA discharge placement after the event, when the hose was restored to the containment clean-up filter to verify effective corrective action was taken as a result of the event described above. The inspectors found the HEPA discharge hose simply wired to the intake at a 90-degree angle with two other HEPA discharges attached in similar fashion at the containment clean-up filter intake. Discussions with the licensee staff indicate the initial placement was similar to the post event attachment. This configuration did not provide a high level of confidence that this was a secure attachment that would assure efficient direction of HEPA discharge to the containment clean-up filter and significantly reduced the possibility of repeat failure.

When the 11 steam generator manway was opened, the iodine and noble gases present in the steam generator migrated to the steam generator platform where a low volume sampler was running. Elevated iodine-131 Derived Air Concentration (DAC) levels were identified at this location. On May 2, 2006, at 8:45p.m., approximately 1 hour and 10 minutes after opening the steam generator 11 hot leg manway, the iodine-131 level was sampled and recorded at 1.18 DAC. Another low volume air sampler was running concurrently on the containment 755' level, and the sample was removed at 8:25 p.m. and identified 0.63 DAC iodine-131. At 11:15 p.m., the containment radiation protection leader received the data, posted the containment building as an Airborne Radioactivity Area and notified workers of the change in conditions in their work areas. At that time, the radiation protection supervisor stopped further entries into containment. Approximately 1-1/4 hours later, based on air sampling data from 8:45 p.m. (1.25 DAC) in the steam generator vault and from 10:35 p.m. (2.37 DAC) 755' level of the containment, the radiation protection supervisor directed the evacuation of non-essential personnel from containment and permitted continuation of the steam generator manway installation and nozzle dam installation work. Twenty minutes, later the general containment building iodine-131 levels reached 2.89 DAC. The highest airborne concentrations recorded during the event were measured at the 755' level of containment on May 3, 2006, at 2:09 a.m., yielding 4.62 DAC.

Post event follow-up testing on the containment clean-up filters was conducted on May 4, 2006, which revealed an iodine-131 retention efficiency of approximately 66 percent compared to the expected efficiency of greater than 90 percent. The containment clean-up filters were not functioning at the expected efficiency and yet were the planned primary method of limiting the iodine-131 contamination in containment when opening the primary system following known fuel leakage during the proceeding operation run. A pre-operational assessment of the operability and efficiency of this engineered safety system was not part of the ALARA planning process. The periodic surveillance of the containment clean-up system was on a 6-year frequency and was last assessed 4 years prior to this event.

Similar levels of iodine-131 in the primary coolant were seen prior to a 2001 outage. When primary systems were opened during that outage there was a slight increase in airborne iodine-131 found in containment air samples and this persisted throughout the outage at less than 0.3 DAC. As a result, 290 workers showed a small but measurable uptake of iodine-131 by the end of the outage and 30 workers received between 10 millirem, the threshold for recording the additional dose, and the highest recorded individual dose was 26 millirem. The collective recorded dose was 446 millirem.

Prior to the above mentioned 2001 outage, primary system iodine-131 levels were identified prior to the outage due to a small fuel leak. The 2001 levels were very similar to the pre-outage levels for the 2006 outage. The 2001 outage demonstrated the ability to work with these levels of iodine-131 in the primary coolant successfully since the 2001 outage did not result in dose significant intakes from airborne iodine-131. Therefore, limited measures were planned in an effort to preclude airborne radioactivity in the containment building during this refueling outage. Contingency plans for containment building contamination were limited to the standing radiation protection procedures for contamination monitoring at access control and disposition of intakes in accordance with Radiation Protection Implementing Procedure (RPIP) 1126, “Contamination Monitor

Alarm Response, and Personnel Decontamination," and non-specific ALARA engineering controls.

The inspectors reviewed a separate event that occurred on May 2, 2006, during the day shift, where the reactor pressure vessel head was vented to the containment building, releasing iodine-131 and noble gases. The licensee's staff presumed the vessel head was vented through a HEPA filter to the containment clean-up filtration that consists of a pre-filter, HEPA and charcoal bank. This error was identified when containment air sampling showed an increase in the airborne radioactivity (iodine-131, 0.4 DAC). No corrective action document was written regarding this event until May 26, 2006. If the licensee had accurately identified this event as a precursor to similar events, it would have provided an opportunity to make self-assessment prior to additional primary system openings. Due partially to the failure to recognize this as a precursor to a more significant event, within 12 hours the containment airborne levels increased again when the steam generator manways were opened and the HEPA filtration was inappropriately positioned in the intake of the containment clean-up filter bank.

Analysis: The inspectors determined that the failure to properly plan ALARA work activities was a performance deficiency and represents a finding as described in IMC 0612, Appendix B, "Issue Screening." ALARA planning did not conduct an adequate assessment of the effect of leaking fuel on the potential for increased iodine and noble gas concentrations in the steam generators and potential impact on the containment building environment. The issue was more than minor because it was associated with the Occupational Radiation Safety cornerstone, and potentially affected the cornerstone attribute of program and process for ALARA planning and exposure/contamination control.

The finding does not involve the application of traditional enforcement, because it did not result in actual safety consequences or the potential to impact the NRC's regulatory function, and was not the result of any willful actions. The finding was evaluated using IMC 0609, Appendix C, the SDP for the Occupational Radiation Safety cornerstone and was determined to be of very low safety significance (Green) because the finding involved an ALARA issue and individuals received very low unintended dose as a result of the procedural noncompliance. However, individual radiation exposures for workers in containment during that time were low relative to regulatory limits; there was not a substantial potential for a worker overexposure; and the licensee's ability to assess worker dose was not compromised.

Enforcement: Technical Specification 5.4.1.a. requires the licensee to establish, implement, and maintain procedures recommended by Regulatory Guide 1.33, Revision 2, Appendix A, date February 1978. Regulatory Guide 1.33 requires procedures for the control of radioactivity and limiting of personnel exposure, ALARA Procedure FP-RP-JPP-01, Radiation Protection Job Planning, Attachment 1, directs the job planner, through a series of planning forms, to assess the radiological safety significance of specific work. The Attachment 1 directs the use of form QF-1203, Radiological Work Assessment; QF-1204, Radiological Work Assessment From Contamination Control, if contamination control was a hazard for the assigned work; and QF-1206, Radiological Work Assessment From Internal Exposure Control, if contamination control internal exposure is a hazard for the assigned work.

Contrary to the above, on March 3 and April 18, 2006, radiation protection personnel assigned to conduct the work assessment, and planning for WO 95654, "11 and 12 Steam Generator Primary Side Manway, and Insert, Remove, and Install," failed to recognize that airborne concentrations for the work were subject to significant changes. Consequently, the licensee did not adequately evaluate the internal exposure hazard and document the hazard in accordance with the above procedure. Since the finding is of very low safety significance and had been entered into the corrective action system as CAP 1027653, the associated violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000282/2006003-03; 05000306/2006003-03).

.3 Job Site Inspections and ALARA Control

a. Inspection Scope

The inspectors observed the following two jobs that were being performed in radiation areas, airborne radioactivity areas, or high radiation areas for observation of work activities that presented the greatest radiological risk to workers:

- steam generator eddy current testing; and
- reactor pressure vessel head removal.

The licensee's use of ALARA controls for these work activities was evaluated using the following:

- The licensee's use of engineering controls to achieve dose reductions was evaluated to verify that procedures and controls were consistent with the licensee's ALARA reviews, that sufficient shielding of radiation sources was provided for, and that the dose expended to install/remove the shielding did not exceed the dose reduction benefits afforded by the shielding.

This review represented one inspection sample.

b. Findings

No findings of significance were identified.

.4 Radiation Worker Performance

a. Inspection Scope

Radiation worker and radiation protection technician performance was observed during work activities being performed in radiation areas, airborne radioactivity areas, and high radiation areas that presented the greatest radiological risk to workers. The inspectors evaluated whether workers demonstrated the ALARA philosophy in practice by being familiar with the work activity scope and tools to be used, by utilizing ALARA low dose waiting areas, and by complying with the work activity controls. Also, radiation worker training and skill levels were reviewed to determine if they were sufficient relative to the radiological hazards and the work involved. This review represented one inspection sample.

b. Findings

No findings of significance were identified

2PS1 Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems (71122.01)

.1 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed the licensee's outage activities related to the radioactive effluent treatment and monitoring program to determine if identified problems were entered into the corrective action program for resolution. The inspectors also verified that the licensee's self-assessment program was capable of identifying repetitive deficiencies or significant individual deficiencies in problem identification and resolution.

The inspectors also reviewed corrective action reports from the radioactive effluent treatment and monitoring program since the previous inspection, interviewed staff and reviewed documents to determine if the following activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk:

- initial problem identification, characterization, and tracking;
- disposition of operability/reportability issues;
- evaluation of safety significance/risk and priority for resolution;
- identification of repetitive problems;
- identification of contributing causes;
- identification and implementation of effective corrective actions;
- resolution of NCVs tracked in the corrective action system; and
- implementation/consideration of risk significant operational experience feedback.

This review represented one inspection sample.

b. Findings

One finding of very low safety significance was identified.

Procedure for Offsite Dose Calculation Manual Compliance Does Not Include Containment Effluent Through Equipment Hatch

Introduction: An inspector-identified finding of very low safety significance and an associated NCV of NRC requirements were identified for the failure to establish adequate written procedure(s) for Offsite Dose Calculation Manual (ODCM) implementation to ensure that the radiological impact from releasing gaseous and particulate effluents from the Unit 1 containment building equipment hatch to the environment was properly assessed prior to the release, and that the release was properly quantified and reported.

Description: On May 5 to May 11, 2006, the Unit 1 containment equipment hatch was open to the atmosphere to allow equipment and personnel in and out of containment in support of a refueling outage and head replacement activities. The negative pressure necessary to prevent uncontrolled releases of radioactive material was not adequately maintained during periods when the equipment hatch was open and allowed air from containment to vent to the atmosphere through the containment building equipment hatch opening. This problem was identified on multiple occasions during this outage by the licensee and by NRC personnel and brought to the attention of the Outage Control Center. This prompted the operations staff to investigate the in-service purge fan alignment and periodically adjust the position of a tarp that was available at the equipment hatch opening to limit the effect of the positive pressure in containment and any release to the environment. The inspectors noted that these interim corrective actions were not consistently implemented. The licensee monitored concentrations of iodine-131 and xenon-133 in the containment air and found that the concentration of gaseous radioactivity was measurable but at very low concentration (less than 0.3 DAC) during the time that the equipment hatch was open. The air contained radioactive material because the primary system was open in several locations and the RCS contained elevated entrained fission gas concentrations at shutdown due to minor fuel degradation which emerged during the unit's run cycle.

The inspectors concluded that the licensee failed to develop an ODCM implementing procedure that ensured that the offsite dose to the public from venting the RCS to containment was properly quantified if the containment came under positive pressure and vented to the environment through the equipment hatch. Additionally, because opening the equipment hatch during the last three outages was a planned evolution, the equipment hatch had become a routine release point. However, the licensee had not revised the ODCM to document the pathway.

Following May 5 to 11, 2006, a period when the equipment hatch was open, and after additional questions raised by the NRC, a corrective action document was subsequently written to evaluate and address the deficiencies with the release assessment process described above. Additionally, this corrective action document, CAP 1027608, "Inadequate Effluent Release Controls at the Unit 1 Equipment Hatch," led to a report, "Quantification of Abnormal Releases Via Roll-up Doors and Equipment Hatch During Refueling Outage 1R24." The inspectors reviewed this document to assure that it:

- described the radiological impact from releasing radioactive effluents through the containment building equipment hatch to the environment, because it was not properly assessed prior to the release;
- demonstrated the offsite dose ALARA objectives of 10 CFR Part 20 and 10 CFR Part 50, Appendix I; and
- ensured that the release was properly quantified and reported.

<u>Analysis</u>: The failure to develop a procedure for ODCM implementation to ensure the radiological impact from releasing radioactive gases to the environment through the equipment hatch was properly assessed prior to the release and that the release was properly quantified and reported in accordance with ODCM requirements represents a performance deficiency as defined in IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening." The inspectors determined that the issue was more than minor because it was associated with the program and process attribute of the Public Radiation Safety cornerstone and potentially affected the cornerstone objective to ensure adequate protection of the public from exposure to radioactive materials from the release

of gaseous effluents. Therefore, the issue was more than minor and represented a finding which was evaluated using the SDP.

Since the finding involved an occurrence in the licensee's radiological effluent monitoring program, the inspectors utilized IMC 0609, Appendix D, “Public Radiation Safety SDP,” to assess its significance. The issue was not associated with radioactive material control; however, the licensee failed to adequately assess the offsite dose impact prior to the releasing radioactive effluents from containment through the equipment hatch; therefore, the situation represented an impaired ability to assess dose. However, the licensee subsequently assessed the offsite dose resulting from the release and determined that applicable dose limits were met. The actual effluent releases, as calculated by the licensee, were not greater than regulatory dose limits or ALARA constraints as defined in the 10 CFR 20.1301(d) or 10 CFR Part 50, Appendix I. The calculated dose to a member of the public using conservative parameters was less than 0.025 millirad. Consequently, there was minimal actual risk to the public from the release; and, therefore, the inspectors concluded that the SDP assessment for this finding was of very low safety significance (Green).

Multiple opportunities to identify and correct deficiencies associated with effluent controls and assessment were presented during outages in 2004, 2005, and 2006. While these were entered into the licensee’s corrective action program, effective corrective action to prevent recurrence was not achieved. The primary cause of this event was a cross-cutting issue related to problem identification and resolution program deficiencies.

<u>Enforcement</u>: Technical Specification 5.5.1 requires that the ODCM contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous effluents. Offsite Dose Calculation Manual, step 7, requires compliance with TS 5.5.4 regarding the Radioactive Effluent Controls Program, which requires that the program be contained in the ODCM, and shall be implemented by procedures. Contrary to this requirement, adequate written procedures were not established to ensure the radiological impact from releasing radioactive effluents through the containment building equipment hatch during outages in 2004, 2005, and 2006, were properly assessed prior to release to demonstrate it satisfied the ALARA design objectives of 10 CFR Part 20 and 10 CFR Part 50, Appendix I. Since the licensee documented this issue in its corrective action program (CAPs 1027608, 1027653, 1028580, and 1029875) and because the violation was of very low safety significance, it is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-282/2006003-04; 50-306/2006003-04).

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

.1 Reactor Safety Strategic Area

a. Inspection Scope

The inspectors reviewed the licensee submittals for two performance indicators for Prairie Island Units 1 and 2, completing four performance indicator verification inspection procedure samples. The inspectors used performance indicator guidance and definitions contained in NEI Document 99-02, Revision 3, "Regulatory Assessment Performance Indicator Guideline," to verify the accuracy of the performance indicator data. The inspectors' review included, but was not limited to, conditions and data from logs, Licensee Event Reports, condition reports, and calculations for each performance indicator specified. The inspectors also reviewed the CAPs listed in the Attachment to this report to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with corrective action procedures.

The licensee's reporting of the following performance indicators were verified:

Unit 1

- Unplanned Power Changes per 7000 Critical Hours for the 2nd Quarter 2004 through the 1st Quarter 2006;
- Safety System Functional Failures for the 2nd Quarter 2004 through the 1st Quarter 2006.

Unit 2

- Unplanned Power Changes per 7000 Critical Hours for the 2nd Quarter 2004 through the 1st Quarter 2006;
- Safety System Functional Failures for the 2nd Quarter 2004 through the 1st Quarter 2006.

Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

Introduction: As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's corrective action program at an appropriate threshold, that adequate attention was given to ensure timely corrective actions, and that adverse trends were identified and addressed. This does not count as an annual sample.

a. Inspection Scope

As discussed in Section 2OS1.1 and 2PS1.1, the inspectors reviewed the licensee's problem identification and resolution program to assess the adequacy of the radiation protection department's ability to identify and document problems and to implement timely and appropriate corrective actions. In particular, the inspectors reviewed the circumstances surrounding an HRA barrier that was found in the open position, which was identified by the NRC on May 9, 2006, and documented in CAP 1029288. To complete the review, the inspectors discussed the issue with several members of the radiation protection staff, supervision and management and reviewed additional licensee-identified HRA barrier issues documented in 4OA7, to determine the adequacy for identifying problems with HRA barriers. Additionally, the inspectors reviewed the circumstances surrounding loss of negative pressure on the containment building when the equipment hatch was open from May 5 to 11, 2006, and the associated effluent assessment as documented in CAP 1027608. To complete the review, the inspectors discussed the issue with several members of the radiation protection and chemistry staff, supervision and management and reviewed additional licensee-identified corrective action documents written in response to similar effluent events during outages in 2004 and 2005.

b. Issues

High Radiation Area Barrier Events

The NRC identified an HRA barrier event during the inspection as discussed in 2OS1.1. The licensee identified multiple similar HRA barrier events as described in 4OA7. Consequently, on June 4, 2006, following the Unit 1 refueling outage, the licensee indicated to the inspectors that they planned to conduct an Adverse Trend of High Radiation Area Control within the scope of the corrective action program (CAP 1033802) using these events and six additional licensee-identified findings as the basis for the review. The inspectors concluded that although individual occurrences of HRA barrier integrity were addressed through repairs as they occurred, the licensee failed to identify the fundamental cause of the problem in a timely manner and allowed the problem to recur during the refueling outage. While the degraded HRA barriers did not result in an occurrence under the occupational exposure control effectiveness performance indicator, it increased the probability of an unauthorized HRA or even Locked High Radiation Area entry and, therefore, represented an additional level of risk.

Lack of Extent of Condition Assessment for Air Flow Problems

In 2004, the licensee generated CAP 38784 to document the loss of negative pressure in containment that resulted in a small release of radioactivity to the environment. The corrective action for that problem included directions for the next outage that governed controls for ventilation pathways when the containment hatch was open. However, the licensee's evaluation was inadequate and the associated corrective actions were not consistently implemented to ensure that the environmental impact from releasing radioactive effluents from containment through the equipment hatch was assessed adequately prior to the release. In 2005, the licensee generated a corrective action CAP 841226 to document the failure to implement the corrective actions specified in 2004 (CAP 38784). However, the licensee's evaluation of that CAP and the associated corrective actions were not sufficiently comprehensive to ensure that the environmental impact from releasing radioactive effluents from containment through the equipment hatch was assessed adequately before the effluent was released. In 2006, the licensee was again presented with lack of control over the airflow at the containment building equipment hatch and again did not ensure that the environmental impact from releasing radioactive effluents from containment through the equipment hatch was assessed adequately before the effluent was released. While the licensee was able to conservatively reconstruct the small radioactive effluents in each instance and record them, the effectiveness of corrective actions lacked rigor. Specifically, the response to the issues was limited in scope, lacked adequate assessment of the extent of condition and failed to result in effective corrective action. The deficiencies with the licensee's problem evaluation and resolution program, a cross cutting issue, significantly contributed to this repetitive problem.

Missed Opportunity to Identify a Precursor to a More Significant Event

On May 2, 2006, the Reactor Pressure Vessel Head was vented to containment releasing iodine-131 and noble gases. The licensee staff thought the venting process was directed through a HEPA filter to the containment clean-up filtration that consists of a pre-filter, HEPA and charcoal bank. This error was identified when containment air sampling showed an increase in the airborne radioactivity. The licensee took immediate action to clear containment until they could understand the source of the elevated levels. This was a precursor or an indicator of the potential for additional and similar events. In fact, within 12 hours the containment airborne levels increased again when the 11 steam generator was opened and the HEPA filtration discharge was inappropriately positioned in the intake of the containment clean-up filter bank. Because the events were similar in result and occurred on the same day, the licensee staff did not initially separate this event from the review of the second event when the 11 steam generator was opened and airborne iodine-131 levels increased. Until the NRC discussed this with the staff and management as a separate event with potentially separate causes and a precursor event, no corrective action document was written. A corrective action program document was written May 25, 2006 (CAP 1032258).

Mistake in Calculating DAC Levels

During the opening of 11 steam generator that lead to an airborne event on May 2, 2006, the licensee collected frequent containment air samples and analyzed them for airborne gaseous and particulate levels. During one of the sampling counts and assessment, a mistake in calculating a DAC was made and it resulted in reporting higher level than was present. While this was a conservative mistake, it did provide information that should have been reviewed for potential program improvement. The need to document this issue was not readily apparent. No corrective action document was immediately written. After discussion of this issue with the NRC, a corrective action program document was written May 22, 2006 (CAP 1031483).

.2 Annual Problem Identification and Resolution Sample

a. Inspection Scope

On April 29, 2006, during the performance of a planned Unit 1 shutdown to perform refueling, operators performed stroking of the pressurizer PORV CV-31232 in accordance with SP 1182A. CV-31232 failed to fully open during the test. This condition was entered into the licensee's corrective action program with CAP 01026977. Initial inspection of the PORV by maintenance personnel identified the most probable cause as galling between the valve plug and cage. The cause was later confirmed during disassembly of the valve.

The inspectors conducted one annual Problem Identification and Resolution inspection sample to review the corrective action aspects associated with this event and a similar occurrence associated with PORV CV-31231. The degraded condition of CV-31231 was found during the previous Unit 1 refueling outage (1R23) and was documented with CAP 039892. The inspectors reviewed the licensee's condition evaluation, engineering documents for the modification of the PORV internals, and the licensee's plans for installation of the new valve internals. The inspectors reviewed PORV maintenance history and discussed PORV historical performance and corrective actions with engineering personnel.

The key documents reviewed by the inspectors associated with this inspection are listed in the Attachment to this report.

b. Findings and Observations

No findings of significance were identified.

.3 Semiannual Problem Identification and Resolution Trend Review

The inspectors performed a semiannual review of the licensee corrective action program to identify trends that could indicate the existence of a more significant safety issue as required by Inspection Procedure 71152, "Identification and Resolution of Problems." This inspection effort completed the required semiannual trending inspection and one inspection sample. The effectiveness of the licensee corrective action program was assessed by comparing trends identified by the licensee with those issues identified by the NRC during the conduct of routine plant status and baseline inspections. Inspectors reviewed CAPs initiated during the period from January 1 through June 20, 2006. The inspectors utilized Pareto analysis and the symptom classification technique to evaluate the CAP data base to select areas for detailed review. The areas selected for detailed review included the Corrective Action Program, the Radiation Protection program, the

Emergency Preparedness program, the Security program, and human performance. The inspectors performed the inspection by in-office review of licensee corrective action program and other reports, including the following:

- trend reports;
- performance indicators;
- equipment problem lists;
- rework reports;
- system health reports;
- program health reports; and
- maintenance rule reports.

b. Findings and Observations

No findings of significance were identified. The inspectors identified that the primary method used by the licensee to identify potential adverse trends is the Department Roll Up Meeting (DRUM). The inspectors identified that the licensee identified potential adverse trends and entered them into the corrective action program for all of the areas selected for detailed review except:

- personnel contaminations;
- radiation protection equipment issues;
- emergency preparedness siren issues; and
- lost badges.

Although these shortcomings within the licensee's trending process were noted, no violations of NRC requirements were identified.

4OA3 Event Followup (71153)

.1 (Closed) Licensee Event Report (LER) 05000306/2006-001-00: Unit 2 Shutdown Required by TSs Due to Inoperable Emergency Diesel Generator

On January 29, 2005, diesel generator D6 was removed from service for planned maintenance. During return-to-service testing, the test was halted due to high crankcase pressure. Investigation attributed the crankcase pressure to piston ring blow-by. Evaluation of the scope of the work indicated that repairs could not be completed within the remainder of the 7-day completion time. Unit 2 was shut down on February 5, 2006. The licensee performed a root cause investigation, implemented corrective actions to prevent recurrence and short term corrective actions, and returned the unit to power operation. The licensee documented the problem, root cause analysis, and corrective actions in CAP 01013473. The LER, root cause analysis report, and corrective actions were reviewed by the inspectors. No findings of significance were identified and no violations of NRC requirement occurred. This LER is closed.

.2 Event Followup of the Inoperability of Both Pressurizer PORVs During Unit 1 Shutdown

a. Inspection Scope

On April 30, 2006, the licensee informed the inspectors that both Unit 1 pressurizer PORVs were inoperable. The licensee was in the process of a shutdown/cooldown of the Unit 1 reactor coolant system and the plant was in a configuration where the pressurizer PORVs were required by TS for the completion of the low temperature-overpressure protection function. The “A” PORV was declared inoperable on April 29, 2006, at 3:21 a.m. when it failed to fully open during surveillance test SP 1182A. The “B” PORV was declared inoperable on April 30, 2006, at 9:00 p.m. when an operator identified the “B” PORV back up air bottle at pressure 1200 pounds per square inch. A minimum bottle pressure of 1800 pounds per square inch is required for an operable back up air supply for each of the PORVs.

The inspectors developed a time line leading up to the declaration of each PORV inoperability and the establishment of a three square inch vent in the reactor coolant system in accordance with the TS. The inspectors compared TS requirements to the actual plant conditions. The inspectors verified the adverse conditions noted with the pressurizer PORVs were promptly entered into the corrective action program; that the licensee implemented appropriate corrective actions to restore compliance with the TS; and the timeliness of those corrective actions were commensurate with the safety significance of the PORV failures.

b. Findings

No findings of significance were identified.

4OA5 Other Activities

.1 Resolution of Unresolved Item (URI) 05000282/2006002-01; 05000306/2006002-01: Evaluation of Expired Sealant Performance for Flood Protection

a. Inspection Scope

The inspectors reviewed the licensee’s efforts to test and demonstrate acceptable performance characteristic of Deck-O-Seal gun grade sealant. The sealant was identified by the inspectors to be 1 year beyond its vendor recommended shelf-life in the previous inspection period. The inspectors concluded that the licensee’s performance deficiency may be minor if the expired sealant was tested and satisfactory performance was demonstrated. The inspectors tracked the resolution of the issue with URI 05000282/2006002-01; 05000306/2006002-01.

b. Findings

Introduction: The inspectors identified a Non-Cited Violation of 10 CFR Part 50 Appendix B, Criterion V, for a combination of an inadequate procedure and a failure to implement the requirements of Surveillance Procedure 1293, Inspection of Flood Control Measures and the Shelf Life Program Procedure FP-SC-PE-05. Specifically, the licensee failed to order and maintain the correct type of Deck-O-Seal sealant to facilitate installation of flood doors and panels in accordance with plant abnormal procedures.

Description: On March 29, 2006, the inspectors inspected the main warehouse to verify the existence of the flood protection materials listed in Table 1 of Surveillance Procedure SP 1293, “Inspection of Flood Control Measures,” Revision 13. All the listed materials were found by inspectors but the Deck-O-Seal sealant was found 1 year beyond its shelf life expiration date.

Deck-O-Seal gun grade sealant is necessary during an exterior flood event to seal seams on eight exterior doors for the turbine, auxiliary, and Unit 2 diesel generator buildings in accordance with the flood bulkhead installation instruction in Abnormal Operating Procedure AB-4, Attachment J, Figure J-1. In addition, AB-4 also specifies the use of the sealant, as needed, to seal any gaps on the 11 exterior flood protection panels for the turbine building, auxiliary building, screenhouse, and Unit 2 diesel generator building in accordance with AB-4, Figure J-2. These doors and panels provide a flood barrier that protects plant safety-related systems and components located below the 705 foot (above mean sea level) elevation in the event of the maximum probable flood.

The condition of the Deck-O-Seal sealant found by the inspectors was not in accordance with SP 1293. The surveillance procedure specified the annual inspection of flood protection features and materials. The licensee completed that inspection on February 17, 2006. Step 7.2.7.C specified that the performer of the flood control measures inspection informs warehouse personnel to order four new kits of the sealant and to dispose of the expired shelf life sealant. This step was signed off as completed. However, upon inspection of the material in the warehouse, the inspectors noted a hand-written date of March 2005 written on the sealant kits. The licensee’s Shelf Life Program procedure FP-SC-PE-05, Revision 0, Step 3.7.2, requires the identifying and labeling of age-sensitive items with a shelf life expiration date on the attached part tag or quality tag as appropriate. The inspectors concluded that the sealant was one year beyond its expiration date.

The inspectors concluded that SP 1293, Step 7.2.7.C was inadequate as written since it only required personnel performing the flood control measures inspections to notify warehouse personnel to order new sealant kits and dispose of the outdated material. There was no action to track the actual completion of the step (i.e., the actual receipt of new and the disposal of the expired sealant).

The inspectors noted that the licensee had failed to follow the Shelf Life Program as required by procedure FP-SC-PE-05. Step 5.3.1 states that the receipt of the sealant and its corresponding shelf life shall be entered into the Material Management System database. The licensee determined that the Deck-O-Seal sealant had not been entered into Material Management System database. This failure resulted in the sealant exceeding its shelf life by one year.

Additionally, during preparation to test the expired sealant, it was discovered that the licensee had historically ordered and received Deck-O-Seal pourable sealant, not the gun grade sealant as specified by SP 1293. The pourable sealant is only acceptable for use in horizontal applications. The sealing of the plant’s flood doors requires a sealant acceptable for vertical application. Upon discovery, the licensee ordered and received, overnighted, the correct sealant.

Analysis: The inspectors reviewed the issue for significance using the guidance provided in IMC 0612, Appendix B, dated September 30, 2005. The inspectors concluded that the issue was a performance deficiency since the warehouse personnel failed to enter the receipt of the material and its associated shelf life into the Material Management System database as required by procedure FP-SC-PE-05; failed to reorder the Deck-O-Seal gun grade sealant as required by SP 1293; and failed to perform an adequate receipt inspection to determine that the sealant received was not the correct sealant for the application (i.e., pourable versus gun grade.)

The inspectors reviewed the examples of minor findings provided in IMC 0612, Appendix E, dated September 30, 2005, and concluded that example 2E closely matched this finding. Specifically, not only did the sealant exceed the shelf life of the vendor, it was also the wrong type of material for this application.

The inspectors completed the significance determination of this finding using IMC 0609, “Significance Determination Process,” dated March 21, 2003, Appendix A, “Determining the Significance of Reactor Inspection Findings for At-Power Situations,” dated December 1, 2004. The Phase 1 Significance Determination worksheet identified that the finding did not contribute to the likelihood of a primary or secondary system loss of coolant accident initiator; the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available; and the finding did not increase the likelihood of a fire or internal or external flooding.

The inspectors concluded that the last Phase 1 SDP criterion of not increasing the likelihood of external flooding was met only after the licensee demonstrated with an evaluation the slow progression (3 days) of the external flooding event, the typically short procurement time (1 day) for the Deck-O-Seal gun grade sealant, and the availability of other potentially acceptable sealants. Therefore, the inspectors concluded that the deficient condition did not increase the likelihood of the external flooding event affecting plant safety-related systems or components and was determined to be of very low safety significance (Green).

Enforcement: The Introduction to 10 CFR 50, Appendix B, states the pertinent requirements of this appendix apply to all activities affecting the safety-related functions of those SSCs: these activities include designing, purchasing, fabricating, handling, shipping, storing, cleaning, erecting, installing, inspecting, testing, operating, maintaining, repairing, refueling, and modifying. Therefore, the external flood protection features associated with the safety-related structures are functions of that structure that ultimately protect the safety-related systems and components contained within those structures. As such, the flood doors associated with this finding must meet the requirements of 10 CFR 50, Appendix B. Specifically, 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” states that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Instructions, procedures, or drawings shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished.

Contrary to the above, on March 29, 2006, inspectors identified that the licensee failed to include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Specifically that Step 7.2.7.C of Surveillance Procedure 1293 failed to track the reorder of new sealant and the removal of the expired sealant until satisfactorily accomplishment. This failure resulted in a critical procedure step to go uncompleted for an extended period of time.

Additionally, the inspectors identified that the licensee had failed to follow procedure FP-SC-PE-05. Specifically, Step 5.3.1 states that the receipt of the sealant and its corresponding shelf life shall be entered into the Material Management System database. The licensee found that the Deck-O-Seal sealant had not been entered into Material Management System database. This failure resulted in the sealant exceeding its shelf life by 1 year.

Finally, the licensee failed to correctly implement SP 1293 in that they had historically ordered, received, and accepted Deck-O-Seal pourable sealant, not the gun grade sealant as specified by the procedure. This resulted in the maintenance of an unusable form of sealant on site for an extended period of time.

Because this violation was of very low safety significance and it was entered into the licensee’s corrective action program with CAPs 01021256 and 01025266, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000282/2006003-05; 05000306/2006003-05).

.2 Partial Completion of Temporary Instruction 2515/166 Pressurized Water Reactor Containment Sump Blockage

a. Inspection Scope

The inspectors completed a partial review of the installation of a plant modification committed to in the licensees response to Generic Letter 2004-02. The inspectors compared the as-built configuration of the new Unit 1 sump B strainer to the design description and applicable drawings and reviewed changes to Unit 1 emergency operating procedures.

b. Findings

No findings of significance were identified.

.3 RVCH and CRDM Housing Replacement (71007)

The original penetration nozzles were fabricated from Inconel Alloy 600 material. These nozzles were welded to the RVCH with a partial penetration weld fabricated from Inconel Alloy 182 weld filler metal. In recent years, several pressurized water reactors have experienced pressure boundary leakage caused by primary water stress corrosion cracking of these materials.

The design of the Unit 1 replacement RVCH is similar to the original, with some notable exceptions as follows:

- the new RVCH is constructed from a single piece forging which eliminates the dome-to-flange weld;
- the new RVCH design eliminates canopy seal welds;
- the new RVCH design eliminates the part length CRDM penetrations; and
- the use of Inconel Alloy 600 was prohibited in fabrication of the new RVCH. For example, the penetration tube material was changed from Inconel Alloy 600 to Inconel Alloy 690 which is more resistant to primary water stress corrosion cracking.

a. Inspection Scope

From April 24 through 28, 2006, from May 1 through 5, 2006, and from May 15 through 19, 2006, the inspectors reviewed the licensee's design changes associated with the Unit 1 RVCH and CRDM housing replacement efforts. Documents reviewed for the Unit 2 RVCH and CRDM housing replacement [refer to Inspection Report 05000282/2005004; 05000306/2005004 (ML052020420)] that were also applicable to the Unit 1 RVCH and CRDM housing replacements were not reviewed as part of this inspection.

The inspectors reviewed certified design specifications, certified design reports, ASME Code reconciliation reports, fabrication deviation notices, non-conformance reports, and design calculations to confirm that the replacement RVCH and CRDM housings were in compliance with the requirements of ASME Boiler and Pressure Vessel Code, Section III, Subsection NB (1998 Edition including addenda through 2000 Addendum). The inspectors confirmed that the design specifications and design reports were certified by registered professional engineers competent in ASME Code requirements. The inspectors confirmed that adequate documentation existed to demonstrate the certifying registered professional engineers were qualified in accordance with the requirements of the ASME Code Section III (Appendix XXIII of Section III Appendices). The inspectors also confirmed that the replacement RVCH and CRDM housings were provided as Code NPT stamped components.

The records reviewed by the inspectors are identified in the Attachment to this report.

b. Findings

No findings of significance were identified.

.4 Head Assembly Upgrade Package (HAUP) (71007)

During the Unit 1 Spring 2006 refueling outage, the licensee elected to install a reactor HAUP that integrated the design of various plant components and structures into the reactor head assembly. This integration involved the re-use of some plant components and the complete replacement of others including:

- CRDM cooling internal ducts;
- new integral reactor vessel missile shield;
- reactor vessel head lift rig;
- CRDM/rod position indication cable drawbridge;
- handrail modifications and new ladders;
- new integral radiation shielding; and
- reactor vessel head insulation.

a. <u>Inspection Scope</u>

From April 24 through 28, 2006, from May 1 through 5, 2006, and from May 15 through 19, 2006, the inspectors reviewed the licensee's design changes associated with the installation of the HAUP. Documents reviewed for the Unit 2 HAUP installation (refer to Inspection Report 05000282/2005004; 05000306/2005004 (ML052020420)) that were also applicable to the Unit 1 HAUP installation were not reviewed as part of this inspection. Specifically, the inspectors reviewed the design specification and a representative sample of design calculations to confirm that HAUP structures and components were designed in accordance with the requirements of the HAUP design specification and the American Institute of Steel Construction and ASME design codes.

The records reviewed by the inspectorate identified in the Attachment to this report.

b. <u>Findings</u>

No findings of significance were identified.

.5 <u>Closure of Unresolved Item</u>

<u>(Closed) URI 05000306/2005004-07</u>: Unable to Determine Significance of HAUP Design Concerns

During the inspection of modifications related to the Unit 2 HAUP installation (refer to Inspection Report 05000282/2005004; 05000306/2005004 (ML052020420)), the inspectors identified a number of HAUP calculation concerns related to design loads, design methods, numerical errors, and the basis for acceptance criteria that were utilized in the calculations. The licensee entered these unresolved issues into their corrective action system as condition report CAP 043325.

From April 24 through 28, 2006, from May 1 through 5, 2006, and from May 15 through 19, 2006, the inspectors reviewed the licensee's corrective actions for the unresolved issues identified in CAP 043325 (CAP 00864144, NRC Head Replacement Questions, dated November 30, 2005). Where necessary, the licensee/vendor revised calculations to resolve the unresolved issues (Calculation Notes CN-RVHP-04-87 and CN-RVHP-04-90). Also, the inspectors determined that LOCA loads (NSAL-05-1, Nuclear Safety Advisory Letter: Reactor Vessel Head Assembly LOCA Loads, dated January 18, 2005) were applied to non-safety-related HAUP structures that could impact safety-related structures (i.e., calculation note CN-RVHP-05-17, Prairie Island Units 1 and 2 - Evaluation of Non-Safety-Related Components for LOCA). The HAUP structures were determined to meet all design code acceptance limits without requiring a modification to the HAUP structure. Therefore, no findings of significance were identified as a result of the original URI concerns.

The inspectors further interviewed licensee staff performing owner's acceptance reviews for Unit 1 HAUP design calculations, reviewed a licensee root cause evaluation related to minor errors in calculations, and reviewed licensee procedures related to design calculations, design interfaces, design verification, and technical review. The inspectors also reviewed a sample of HAUP design calculations during inspection activities for the Unit 1 HAUP installation. No findings of significance were identified. (Section OA5.2)

In summary, no violations were identified. This item is closed.

.6 Replacement Head Installation and Testing (71007)

a. Inspection Scope

The inspectors reviewed documents and activities associated with the head replacement and post-installation verification and testing, including:

- temporary modifications;
- rigging procedures, safe load path, and laydown areas;
- the controls and plans to minimize adverse impact on the operating unit and common systems; and
- post-installation inspection, leakage testing, and equipment performance.

b. Findings

No findings of significance were identified.

4OA6 Meeting(s)

.1 Exit Meeting

The inspectors presented the inspection results to Mr. T. Palmisano and other members of licensee management at the conclusion of the inspection on July 12, 2006. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Interim Exit Meetings

Interim exits were conducted for:

- Reactor vessel head replacement procedure (IP 71007) with Mr. T. Palmisano, Site Vice President, and other members of the licensee's staff on May 19, 2006. The licensee confirmed that the design documentation prepared by WEC and MHI was considered proprietary. It was agreed that all copies of proprietary documentation not returned to the licensee would be shredded.

- Outage Access Control to Radiologically Significant Areas and ALARA Program inspection with Mr. P. Huffman, Plant Manager, and Mr. T. Palmisano, Site Vice President, on May 12, 2006; and Mr. P. Huffman, Plant Manager, on May 25, 2006.

- Inservice Inspection IP 71111.08 with Mr. Steve Brown on June 9, 2006.

4OA7 Licensee-Identified Violations

The following violations of very low significance (Green) were identified by the licensee and are violations of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Manual, NUREG-1600, for being dispositioned as NCVs.

Cornerstone: Mitigating Systems

10 CFR 50.65(a)(4) requires that risk be assessed and managed for maintenance. Contrary to this, on May 6, 2006, risk was incorrectly calculated as Yellow following the unplanned unavailability of the 121 instrument air compressor concurrent with the planned unavailability of diesel generator D2, 11 cooling water pump, safeguards 4 kilovolt bus 16, and the 12 AFW pump. Consequently, compensatory actions and contingency plans were not identified for an Orange risk condition as required by the licensee’s procedure H24.1, “Assessment and Management of Risk Associated with Maintenance Activities.” This was identified in the licensee’s corrective action program as CAP 01028790. This finding is of very low safety significance because the air compressor was repaired and returned to service within the risk informed allowed outage time.

10 CFR 50, Appendix B, Criterion III, Design Control, requires that measures be established to assure that deviations from quality standards are controlled. Contrary to this, on May 11, 2006, it was identified that non-safety-related parts were used in safety-related 4 kilovolt switchgear to fasten the shutter guide to the fixed shroud. This was part of an ongoing maintenance practice that replaced broken nylon bolts with supplies from non-safety-related shop supplies. This was identified in the licensee’s corrective action program as CAP 01029449. This finding is of very low safety significance because there were no failures that resulted in safety-related equipment becoming inoperable.

Cornerstone: Occupational Radiation Safety

The licensee’s TS 5.7.1 a. states that for High Radiation Areas accessible to personnel, each entryway to such an area shall be barricaded. Contrary to this, on May 1, 2006, the licensee identified that a radiation worker removed a High Radiation Area boundary swing gate (barricade) at the access to the top of the Unit 1 pressurizer vault to position one leg of the stand for the Pressurizer Missile Shield without receiving approval for removing the barricade from the Radiation Protection staff. Upon identifying the noncompliance, the Radiation Protection staff walked-down the pressurizer vault to ensure all personnel were on a High Radiation Area Radiation Work Permit, validated all Locked High Radiation and High Radiation Area postings in Unit 1 containment and auxiliary building, and started a Human Performance Event Investigation (CAP 01027384). The finding was of very low safety significance because it did not result in an unmonitored or unplanned personnel exposures as a result of the barrier loss.

The licensee's TS 5.7.1 a. states that for High Radiation Areas accessible to personnel, each entryway to such an area shall be barricaded. Contrary to this, on May 29, 2006, Radiation Protection staff identified that a radiation worker removed a High Radiation Area boundary swing gate (barricade) at the access to 12 RHR vault and it remained in the open position. Upon identifying the noncompliance, the Radiation Protection staff corrected the swing gate position and repaired a guide that was improperly placed and caused the swing gate to bind allowing it to remain open. Additionally, the staff walked-down all similar High Radiation Area swing gates to verify that the gates were operating properly (CAP 01032792). The finding was of very low safety significance because it did not result in an unmonitored or unplanned personnel exposures as a result of the barrier loss.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
T. Palmisano, Site Vice President
P. Huffman, Plant Manager
J. Anderson, Radiation Protection and Chemistry Manager
S. Brown, Engineering Director
W. Collins, Nuclear Oversight Supervisor
R. Cooper, Reactor Head Replacement Project Engineer
F. Forrest, Operations Manager
S. Hansen, ISI Coordinator
J. Kivi, Senior Regulatory Compliance Engineer
C. Koehler, Reactor Head Replacement Project Manager
J. LeClair, Radiation Protection General Supervisor
S. Northard, Nuclear Safety Assurance Manager
F. Ortiz, Structural Engineer - Reactor Head Replacement Project
G. Park, Fleet ISI Supervisor
S. Redner, Eddy Current Testing Program Manager
C. Sprout, Structural Engineer - Reactor Head Replacement Project
S. Thomas, Engineering Supervisor
J. Wren, NDE Level III

Nuclear Regulatory Commission

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000282/2006003-01;	NCV	Updated Safety Analysis Report Change That Removed the Reactor Vessel Head Lift Elevation Limit and Reference to the Associated Reactor Vessel Head Load Drop Calculation
05000282/2006003-02; 05000306/2006003-02	NCV	NRC Identified Loss of High Radiation Area Barricade at Unit 1 Pressurizer Missile Shield
05000282/2006003-03; 05000306/2006003-03	NCV	Alara Planning Does Not Identify and Prepare for Potential Airborne Conditions When Opening the Steam Generator Manways
05000282/2006003-04; 05000306/2006003-04	NCV	Procedure For ODCM Compliance Does Not Include Containment Effluent Through Equipment Hatch
05000282/2006003-05; 05000306/2006003-05	NCV	Failure to Follow Procedures for External Flooding

Closed

05000306/2005004-07	URI	Unable to Determine Significance of HAUP Design Concerns
05000306/2006-001-00	LER	Unit 2 Shutdown Required by TSs Due to Inoperable Emergency Diesel Generator
05000282/2006003-01;	NCV	Updated Safety Analysis Report Change That Removed the Reactor Vessel Head Lift Elevation Limit and Reference to the Associated Reactor Vessel Head Load Drop Calculation
05000282/2006003-02; 05000306/2006003-02	NCV	NRC Identified Loss of High Radiation Area Barricade at Unit 1 Pressurizer Missile Shield
05000282/2006003-03; 05000306/2006003-03	NCV	Alara Planning Does Not Identify and Prepare for Potential Airborne Conditions When Opening the Steam Generator Manways
05000282/2006003-04; 05000306/2006003-04	NCV	Procedure For ODCM Compliance Does Not Include Containment Effluent Through Equipment Hatch
05000282/2006003-05; 05000306/2006003-05	NCV	Failure to Follow Procedures for External Flooding

Discussed

None.

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety but rather that selected sections of portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

1R01 Adverse Weather

Tornado and High Winds
SP 1039; Tornado Site Hazard Inspection; Revision 11
CAP 01027731; Tornado Hazard Found in Cooling Tower Equipment House Area
CAP 01027770; Security Equipment Meets Tornado Hazard Criteria per SP 1039
Design Basis Document DBD Topical 05; Hazards; Revision 2
IPEEE; NSPLMI-96001; Revision 1

Hot Weather Preparations
Periodic Test Procedure TP 1636; Summer Plant Operation; Revision 20
Integrated Checklist 1C37.10-1; D1/D2 Diesel Generator Room Cooling; Revision 5
Integrated Checklist 2C37.10-1; D5/D6 Diesel Generator Building HVAC; Revision 4
Operating Procedure C34; Station Air System; Revision 32
CAP 01035016; MD-32427 Did Not Close During TP 2296B
CAP 01035844; NRC Found 2 Temperature Switches On D1/D2 Not in Checklist Position

1R02 Evaluation of Changes, Tests, or Experiments

Design Change 03RV05 Part 1; Replace Unit 1 and 2 Reactor Vessel Heads and Associated Components; Revision 1
Design Change 03RV05 Part 2; Reactor Vessel Head Assembly Upgrade Package; Revision 1
10 CFR 50.59 Evaluation 1052; Heavy Loads Licensing Bases; Revision 0
10 CFR 50.59 Evaluation 1052; Heavy Loads Licensing Bases; Revision 1
10 CFR 50.59 Screening 2123; Design Change 03RV05 Part 1, Documents Related to RCGVS and RVLIS Pipe and Supports; Revision 2
10 CFR 50.59 Screening 2125; Design Change 03RV05 Part 2, HAUP Documents Related to the Reactor Vessel CRDM Seismic Platform, Seismic Spacer Plate, Adjustment Plate Assembly, Cable Supports; Revision 1
10 CFR 50.59 Screening 2127; Design Change 03RV05 Part 2, HAUP Documents Related to CRDM Cooling: Coils, Fans, Pipe/Pipe Supports and Instrumentation and Control; Revision 3
10 CFR 50.59 Screening 2149; Replace Unit 1 and Unit 2 Reactor Vessel Head Internal Insulation; Revision 0
10 CFR 50.59 Screening 2395; Design Change 03RV05 Part 1, Abandon Upper Range RVLIS Indication; Revision 0
10 CFR 50.59 Screening 2628; Design Change 03RV05 Part 2, Unit 1 and Unit 2 Evaluation of Non-Safety-Related Components for LOCA; Revision 0
PINGP USAR; Section 12.2.12.1.4; Containment Polar Crane Evaluation; Revision 27

1R04 Equipment Alignment

D2 Diesel Generator
Integrated Checklist C1.1.20.7-1; D2 Diesel Generator Valve Status; Revision 20
Integrated Checklist C1.1.20.7-2; D2 Diesel Generator Auxiliaries and Local Panels and Switches; Revision 9
Integrated Checklist C1.1.20.7-3; D2 Diesel Generator Main Control Room Switch and Indicating Light Status; Revision 15
Integrated Checklist C1.1.20.7-4; D2 Diesel Generator Circuit Breakers and Panel Switches; Revision 12

12 Motor-Driven AFW Pump
System Prestart Checklist C28-15; 12 Motor-Driven AFW Pump; Revision 4

D6 Diesel Generator
Integrated Checklist C1.1.20.7-13; D6 Diesel Generator Valve Status; Revision 14
Integrated Checklist C1.1.20.7-14; D6 Diesel Generator Auxiliaries and Local Panels and Switches; Revision 12
Integrated Checklist C1.1.20.7-15; D6 Diesel Generator Main Control Room Switch and Indicating Light Status; Revision 6
Integrated Checklist C1.1.20.7-16; D6 Diesel Generator Circuit Breakers and Panel Switches; Revision 8

1R05 Fire Protection

Plant Safety Procedure F5, Appendix A, Revision 15; Fire Strategies for Fire Areas 1, 18, 20, 68, 102, 106, 114, 118, and 122
Plant Safety Procedure F5, Appendix F, Revision 19; Fire Hazard Analysis for Fire Areas 1, 18, 20, 68, 102, 106, 114, 118, and 122
CAP 01028593; Fire Protection SP 1183A Did Not Contain Appropriate Information

1R06 Flood Protection Measures (Internal)

Administrative Work Instruction 5AWI 8.9.0; Internal Flooding Drainage Control; Revision 2
Procedure H36; Plant Flooding; Revision 0
CAP 01011939; Yellow Slippery When Wet Sign Found in Plant Screenhouse
CAP 01033787; High Radiation Area May Be a Critical Drainage Path

1R07 Heat Sink Performance

Maintenance Procedure D104.1; Zebra Mussel Control Treatment: Circulating Water System; Revision 2
50.59 Evaluation 1025; Zebra Mussel Treatment; Circulating Water System; April 11, 2006
Operator Logs for April 19 - 21, 2006

1R08 Inservice Inspection Activities

Documents Associated with ASME Code Nondestructive Examinations (NDEs) Observed

Section Work Instruction (SWI) NDE-UT-16A; Ultrasonic Examination of Austenitic Piping Welds to Appendix VIII; dated March 2006
SWI NDE-VT-2.0; Visual Examination of Components & Their Supports; dated March 2006
SWI NDE-FE-1; Inservice Inspection Flaws Evaluation And Disposition; dated March 2006
SWI NDE-ET-5; Site Specific Performance Demonstration; dated March 2006
CAP 01027487; 5 ISI Indications Not Written Into CAP Within 24 hours; dated May 2, 2006

Documents Associated with Disposition of Relevant Indications
Report 2004P034; Liquid Penetrant Examination; dated October 22, 2004
Report 2004P034; ISI Flaw Sizing Worksheet; dated October 22, 2004
Report 2004P034; ISI Flaw Disposition Worksheet; dated October 24, 2004

Corrective Action Program Documents for Evaluations for Boric Acid Leakage
SP 1405; Unit 1 Mid-Cycle and Refueling Outage Boric Acid Corrosion Examination Inside Containment; Revision 1
CAP 00847672; Evaluate or repair boric acid leak affecting RH-10-2
CAP 01026969; ASME XI and BACC Relevant Body to Bonnet Leak on CV-31450
CAP 01026980; Boric Acid Leak from SI-199-2 Packing Found
CAP 01026983; SI-15-1 Packing Leak Identified
CAP 01027012; Unit 1 MV-32230 has Boric Acid Residue from Packing Leak
CAP 01027041; Relevant Indication on RC-1-4, Loop B to 11 Reactor Coolant Drain Tank
CAP 01027046; Relevant Indication on Flow Transmitter 1FT-412
CAP 01027048; Relevant Boric Acid Leak on MV-32068
CAP 01027052; Potentially Relevant Indication on RC-1-8
CAP 01027054; Relevant Boric Acid Leak on MV-32070
CAP 01027091; Boric Acid Leak on Flow Transmitter 1FT-628
CAP 01027103; Boric Acid Leak on CV-31447
CAP 01027175; Relevant Indication on MV-32065

Documents Associated with Steam Generator Examinations
SWI NDE-ET-5; Site Specific Performance Demonstration; dated April 21, 2006
1H25.1; Unit 1 Assessment of Steam Generator Tube Degradation Mechanisms; dated April 21, 2006

Corrective Action Program Documents
CAP 01027249; ISI Exam Found Lugs on Snubber (SIRH-9) Welded to Clamp; dated May 1, 2006
CAP 01027258; ISI Exam Revealed Loose Nuts on Snubber (SIRH-11); dated May 1, 2006
CAP 01027266; ISI Exam Revealed Insufficient Thread Engagement; dated May 1, 2006

1R11 Licensed Operator Requalification Program

Simulator Evaluation Guide P9160S-001, ATT SQ54; Revision 0
Administrative Work Instruction 5AWI 3.15.0; Plant Operation; Revision 17

1R12 Maintenance Effectiveness

Maintenance Rule Status Chart; June 27, 2006
CAP 01012627; 124 Station Air Compressor Jacket Cooling Outlet Temperature High
CAP 01013896; PM 3505-1-121, 121 Instrument Air Compressor 1000 Hour Inspection
CAP 01025330; System Review Found 122 Compressor Unavailability Remains Greater Than 75 Percent
CAP 01035713; 122 Air Compressor Making Unusual Noises Upon Return to Service

1R13 Maintenance Risk Assessments and Emergent Work Control

Procedure H24.1; Assessment and Management of Risk Associated with Maintenance Activities; Revision 9
Unit 2 Configuration Risk Assessment for April 5, 2006
Operator Logs for April 5, 2006
Unit 2 Configuration Risk Assessment for April 13, 2006
Operator Logs for April 13, 2006
CAP 01024351; NRC Resident Questions on PRA for Partial Trip Condition
Unit 1 Configuration Risk Assessment for April 24, 2006
Operator Logs for April 24, 2006
Unit 1 Configuration Risk Assessment for April 28, 2006
Operator Logs for April 28, 2006
Unit 2 Configuration Risk Assessment for May 5, 2006
Operator Logs for May 5, 2006
Electrical Maintenance Procedure PE TA121&122; Transfer 480Volt Safeguards Buses 121 & 122 to Alternate Source; Revision 1
Unit 2 Configuration Risk Assessment for May 8, 2006
Operator Logs for May 8, 2006
CAP 01003450; Emergent Work Affecting Scheduled Work
Unit 1 Configuration Risk Assessment for June 15, 2006
Operator Logs for June 15, 2006
Unit 1 Configuration Risk Assessment for June 28, 2006
Operator Logs for June 28, 2006

1R14 Nonroutine Evolutions

Operator Response to Unit 1 Manual Reactor Trip
Operator Logs for April 14, 2006
CAP 01024213; Unit 1 Reactor Tripped After Losing 50% FW Flow from 100%

Operator Response to a Unit 2 Overpower Transient
Operating Logs from May 16 and 17, 2006
CAP 01030453;Possible Power Excursion Above Licensed Level of 1650 MWth [Mega-Watts thermal]

1R15 Operability Evaluations

CAP 01011542

CAP 01011542; Loose Material Found in Unit 1 Residual Heat Removal Pump Pit Flood Barrier (prompt operability assessment)
CAP 01011542-02; Loose Material Found in Unit 1 Residual Heat Removal Pump Pit Flood Barrier (historical operability assessment)

VC-24-1

CAP 01032647; Relief Valve Not Tested During 1R24
OPR 000531; VC-24-1 Not Tested Within American Society Mechanical Engineers Required Frequency; Revision 1
CAP 01032647 Attachment; Justification for Deferral of VC-24-1 Testing
VC-24-1 Radiological Analysis
Risk Evaluation V.SPA.06.007; VC-24-1 Relief Valve Missed IST Test

Feedwater Pipe Support 1-FWH-35

CAP 01033009; Discrepancies in FW Support 1-FWH-35
OPR 01033009; Discrepancies in FW Support 1-FWH-35; Revision 01
Letter from Automated Engineering Services Corp. to Prairie Island Nuclear Generating Plant; Evaluation of Unit 1 SG 11 FW Line Force Restraints #2 and As-Found Condition; May 30, 2006
Letter from Automated Engineering Services Corp. to Prairie Island Nuclear Generating Plant; Evaluation of Unit 1 SG 11 FW Line Support FWH-35 and Force Restraints #10 and As-Found Condition; May 30, 2006

11 Turbine-Driven AFW Pump

CAP 01034749; 11 Turbine-Driven AFW Pump Turbine Outboard Bearing Temperature
CAP 01035796; NRC Question Regarding 11 Turbine-Driven AFW Pump Bearing Temperature
CAP 01037612; Insulation Appeared to be Missing from 11 Turbine-Driven AFW Pump During 1R24

1R19 Post-Maintenance Testing

Diesel Generator D2 Cylinder Liner Replacement

WO 99200; D2 Emergency Diesel Generator Run-In
SP 1305; D2 Diesel Generator Monthly Slow Start; Revision 35
SP 1307; D2 Diesel Generator 6-Month Fast Start Test; Revision 29
SP 1335; D2 Diesel Generator 18-Month 24-Hour Load Test; Revision 8
CAP 01031446; D2 Coolant System Cloudy After Cylinder Replacement

CV-31998 Back Up Air Supply Inlet Check Valve Replacement

WO 0509256; Replace Air Supply to Accumulator Check Valves
WO 100114-03; Replace Air Regulator to Control Valve
CAP 01032809; 11 Turbine-Driven AFW Pump Steam Admission Valve Accumulator Check Valve Test

Repacking of 11 Turbine-Driven AFW Pump Valves AF-13-3 and CV 31998
WO 88083; Replace Packing in AF-13-3
WO 88959; Replace Packing in CV- 31998
SP 1102; 11 Turbine-Driven AFW Pump Monthly Test
CAP 01025020; Work Order at a “Finished” Status but PMT Not Performed

Control Valve CV-31235
SP 1089A, Train A RHR Pump and Suction Valve from Refueling Water Storage Tank Quarterly Test; Revision 10

1N36 Cable Replacement
WO 286940; Replace 1N36 Detector
Maintenance Procedure D35.1; Nuclear Indication System Source and Intermediate Range Detector Replacement
SP 1318.2; Nuclear Indication System Intermediate Range Calibration; Revision 12
Temporary Modification 8315; Replacement of the Damaged 1N36 Wires with Existing Spare Wires
CAP 01009682; Hot Leg Sample Valve Not Assembled Correctly

11 Turbine-Driven AFW Pump Turbine Bearing Replacement
SP 1103; 11 Turbine-Driven AFW Pump Once Every Refueling Shutdown Flow Test; Revision 42
CAP 01034748; Temperature Limits For Turbine Bearings in SP 1330/2330
CAP 01034749; 11 Turbine-Driven AFW Pump Turbine Outboard Bearing Temperature

1R20 Refueling and Other Outage Activities

Operating Procedure 1C1.2; Unit 1 Startup Procedure; Revision 37
Operating Procedure 1C1.3; Unit 1 Shutdown; Revision 57
Operating Procedure 1C4.1; RCS Inventory Control - Pre-Refueling’ Revision 18
Alarm Response Procedure 47006-0507; 1G Generator Potential Transformer Volt Balance; Revision 19
Special Operations Procedure 1D2; RCS Reduced Inventory Operation; Revision 19
CAP 01027489; Issues Associated With C4.1 Draindown of Unit 1 RCS
Special Operations Procedure D5.2; Reactor Refueling Operations; Revision 45
CAP 01031485; Unclear Procedure Guidance for Unit 1 D58

1R22 Surveillance Testing

SP 2093
SP 2093; D5 Diesel Generator Monthly; Revision 77
CAP 01025789; Low Lubricating Oil Level on D5 Engine 1 and 2 During Slow Start Run
CAP 01025471; Low Lubricating Oil Sump Level on D5 Engine 1 and 2 During SP 2093

SP 1405
SP 1405; Unit 1 Mid-Cycle and Refueling Outage Boric Acid Corrosion Examinations Inside Containment; Revision 1
SP 1407; Leakage Examination of Canopy Seals, Mechanical Joints, and Other Pressure Retaining Components on the Reactor Head; Revision 0

Relevant Boric Acid CAPs including: 01026969, 01027041,01027046, 01027048, 01027052, 01027054, 01027091, 01027103,and 01027175

SP 1088A
SP 1088A; Train A Safety Injection Quarterly Test: Revision 10

SP1092
SP1092B; Safety Injection Check Valve Test (Head Off) Part B: Refueling Water Storage Tank to RHR Flow Path Verification; Revision 14
SP1092C; SI Check Valve Test (Head Off) Part C: Accumulator Flow Path Verification; Revision 10

SP1072.45
SP 1072.45; Local Leakage Rate Test of Penetration 45 (Reactor Water Makeup); Revision 17
CAP 01027222; Unit 1 RMU to Demin Crosstie RC-4-12

SP 1106C
SP 1106C; 121 Cooling Water Pump Quarterly Test; Revision 28
CAP 01031679; 121 Motor-Driven Cooling Water Pump Performance in the Action Range

SP1083
SP 1083, Unit 1 Integrated SI Test With a Simulated Loss of Offsite Power; Revision 31
CAP 01032656; BOP Power Failure Annunciator with NSSS Trouble Alarm
CAP 01032658; All Inverter AC Input Breakers Tripped Open During SP 1083
CAP 01032779; High Standards Not Exhibited During SI Briefings

SP 1750
SP 1750; Post-Outage Containment Closeout Inspection; Revision 30
CAP 01033737; Scaffold Knuckle Found In Containment

SP 1070
SP 1070; Reactor Coolant System Integrity Test; Revision 37

1R23 Temporary Modifications

4T-175
Maintenance Procedure 1D108; Pressurizer PORV Air Accumulator Supplementation; Revision 1
ENG-ME-592; Determine the Minimum Amount of Air Pressure to Fully Stroke Pressurizer PORV; Revision 0
ENG-ME-584; Sizing of Supplemental Air for Pressurizer PORV Air Accumulators; Revision 0
NSP-04-189; Data on Pressurizer PORV Cycling During Cold Overpressure Mitigation System Transients - New Analysis
CAP 01027161; Air Leak on Union Between CV-31231 and Solenoid Valve

1EP6 Drill Evaluation

Simulator Evaluation Guide P9160S-001, ATT SQ54; Revision 0

2OS1 Access Control to Radiologically Significant Areas

CAP 1027384; Removal of High Radiation Boundary by Unauthorized Personnel; May 1, 2006
CAP 1028608; Worker Removed Radiation Boundary to By-pass Turnstile at Access; May 8, 2006
CAP 1029288; High Radiation Area Swing Gate Turned Due to Loose Base; May 10, 2006
CAP 1031277; Potential For An Individual to Be Locked Inside a High Radiation Area; May 19, 2006
CAP 1032258; Radiation Protection and Chemistry Group Threshold for Corrective Action Program Initiation is Too High; May 25, 2006
CAP 1032792; 12 Residual Heat Removal High Radiation Area Swing Gate Did Not Close; May 29, 2006
CAP 1033802; Adverse Trend High Radiation Area Control; June 4, 2006
CAP 1028608; Violation of Radiation Boundary; May 8, 2006
CAP 1032220; Locked High Radiation Area Barrier to Spent Resin Tank Area Found Unsecured; May 25, 2006
CAP 1028824; Temporary Radiation Controlled Area for Reactor Head Planned Too Large, May 9, 2006
PINGP 258; Radiation Protection Survey Record, Spent Resin Tank Room; May 5, 2006

2OS2 As Low As Is Reasonably Achievable Planning and Controls (ALARA)

ACE 1027653; Elevated Iodine-131 Level in Unit 1 Containment During 1R24; June 9, 2006
CAP 1027645; High Airborne Unit 1 Containment Due to Steam Generator Venting; May 3, 2006
CAP 1028594; Control of Receipt Area Roll Up Doors Poor; May 7, 2006
CAP 1029400; Auxiliary Building and Spent Fuel Pool Vent Releases Higher Than Expected; May 10, 2006
CAP 1029875; Radiation Protection Chemistry Does Not Have Plan for Challenges to Offsite Dose Calculation Limits; May 13, 2006
CAP 1031483; Incorrect Air Sample Data; May 22, 2006
CAP 1032424; Head Vent to Atmosphere Lacking High Efficiency Particulate Air Ventilation; May 29, 2006
CAP 1035274; Internal Dose from Iodine-131 Excursion in Unit 1 Containment; June 13, 2006
CAP 1029247; Work on SI-9-2 Stopped Due to Exceeding Work Order Dose Estimate; May 10, 2006
CAP 1029271; Passport Dose Report is Inaccurate; May 10, 2006
1D27.39; Initial Steam Generator Outage Work Activities; Revision 0
QF-1203; Radiological Work Assessment Form; Revision 2
QF-1204; Radiological Work Assessment Form Contamination Control; Revision 0
QF-1205; Radiological Work Assessment Form Exposure Control; Revision 0
QF-1206; Radiological Work Assessment Form Internal Exposure Control; Revision 1
QF-1207; Radiological Planning Checklist; Revision 0
QF-1209; Radiological Re-Job Briefing Form; Revision 0
RPIP 1126; Contamination Monitor Alarm Response and Personnel Decontamination; Revision 21

RWP 563; Primary Manway Insert and Remove, Revision 0
RWP 609; Eddy Current Testing of Steam Generator Tubes, Revision 0
WO 95654; 11 and 12 Steam Generator Primary Side Manway Insert Remove and Install
WO 95655; 95656; 11 and 12 Primary Side Eddy Current Testing of Steam Generator Tubes
WO 95727; Disassemble Reactor In-Accordance-With D3; May 2, 2006
WO 99051; Sump C When Hosted High Radiation Area; February 27, 2006
Minutes of Emergent Site ALARA Committee Meeting; May 10, 2006

2PS1 Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems

CAP 1027608; Inadequate Effluent Release Controls at the Unit 1 Equipment Hatch; May 2, 2006
CAP 1028580; Lack of Communication for Effluent Release; May 7, 2006
CAP 1032260; Effluent Control - Process and Procedures; May 25, 2006
CAP 42127; Control of Air Flow in Containment/Annulus Was Not Maintained Negative; May 4, 2005
CE 007761; Corrective Actions Specified in CAP 038784 Were Not Effectively Implemented for 2R-23; May 5, 2005
1C19.2; Containment System Ventilation - Unit 1; Revision 15
C19.10; Containment Airlock Door Control at Shutdown; Revision 21
C19.9; Containment Boundary Control During Mode 5, Cold Shutdown and Mode 6, Refueling; Revision 12
1D61.4; Equipment Hatch Removal and Installation Procedure - Unit 1; Revision 5
RPIP 3001; Plant Shutdown Guidelines; Revision 10
RPIP 4509; Containment Release Instructions; Revision 11
RPIP 4511; Airborne Continuous Release Report; Revision 8
TS 5.5 Radioactive Effluent Controls Program
2005 Annual Radioactive Effluent Report and Offsite Dose Calculation Manual; May 9, 2006

4OA1 Performance Indicator Verification

Prairie Island Nuclear Generating Plant Form 1318C; Performance Indicators-Safety System Functional Failures; Revision 0 for 2nd Quarter 2004, 3rd Quarter 2004, 4th Quarter 2004, 1st Quarter 2005, 2nd Quarter 2005, 3rd Quarter 2005, 4th Quarter 2005, and 1st Quarter 2006
Prairie Island Nuclear Generating Plant Form 1318A; Performance Indicators-Initiating Events; Revision 0 for 2nd Quarter 2004, 3rd Quarter 2004, 4th Quarter 2004, 1st Quarter 2005, 2nd Quarter 2005, 3rd Quarter 2005, 4th Quarter 2005, and 1st Quarter 2006
Plant Procedure H33; Performance Indicator Reporting; Revision 5
Plant Procedure H33.1; Performance Indicator Reporting Instructions; Revision 5
Plant Procedure H33.3; Safety System Functional Failure Performance Indicator Reporting Instructions; Revision 1
Unit 1 and 2 Operating Logs for April 1, 2004 through March 31, 2006
CAP 01031984; Evaluate D6 High Crankcase Pressure for MSPI [Mitigating System Performance Index] Failure
CAP 01024901; Data Error - Did Not Report 11.9 Hours of Unavailability for D1 Diesel Generator

4OA2 Identification and Resolution of Problems

T-Track CAP 039892; CV31231 Unit 1 Pressurizer PORV Appears to be Leaking

CAP 01026977; CV-31232 Pressurizer PORV Had Dual Indication During SP 1182A
Condition Evaluation 00666; CV31231 Unit 1 Pressurizer PORV Appears to be Leaking
Engineering Work Request 009993; Issue an Equipment Change to Replace Pressurizer PORV Trim with a Trim Made of 400 Series Stainless Steel
Engineering Work Request 009995; Issue an Equipment Change to Install the Manufacturers Horizontal Mounting Kit on the Pressurizer PORVs
Apparent Cause Evaluation 1026977-01: CV-31232 Pressurizer PORV Had Dual Indication During SP 1182A

4OA3 Event Followup

Event Followup of the Inoperability of Both Pressurizer PORVs During Unit 1 Shutdown
Prairie Island TSs, Section 3.4.11; Pressurizer PORVs; Amendment 167
Prairie Island TSs, Section 3.4.13; Low Temperature-Overpressure Protection; Amendment 158
USAR, Section 4; Mass and Heat Input Events; Revision 27
Temporary Modification 4T175; Pressurizer PORV air Accumulator Supplementation
SP 1181; Overpressure Protection System Setpoint Verification; Revision 22
SP 1182A; Overpressure Protection System Functional Test; Revision 14
CAP 01026977; CV-31232 Pressurizer PORV Had Dual Indication During SP 1182A
CAP 01027161; Air Leak on Union Between CV-31231 and Solenoid Valve

4OA5 Other Activities

Resolution of URI 05000282/2006002-01; 05000306/2006002-01
Abnormal Operating Procedure AB-4; Flood; Revision 28
SP 1293; Inspection of Flood Control Measure; Revision 13; performed February 7 through 17, 2006
Fleet Procedure FP-SC-PE-05; Shelf Life Program; Revision 0
CAP 01021256; Deck-O-Seal Sealant Found with Questionable Shelf Life
CAP 01022931; Re-Order of Sealant Not Completed
CAP 01025266; Incorrect Sealant Placed In Stock
Condition Evaluation 01021256-04; Flood Panels and Doors - Deck-O-Seal Issue

Partial Completion of Temporary Instruction 2515/166 on Unit 1
Design Description Form for EC Number 0378; Containment Sump B Screen Replacement; Revision 0
Drawing SFS-PI-PA-7165; Strainer Cover; Revision 2
Drawing SFS-PI-PA-7164; Strainer Piping A5 and B5; Revision 4
Drawing SFS-PI-PA-7163; Strainer Piping A4 and B4; Revision 4
Drawing SFS-PI-PA-7162; Strainer Piping A3 and B3; Revision 3
Drawing SFS-PI-PA-7161; Strainer Piping A2 and B2; Revision 4
Drawing SFS-PI-PA-7160; Strainer Piping A1 and B1; Revision 1
Drawing SFS-PI-PA-7150; Mounting Track Assembly; Revision 1
Drawing SFS-PI-PA-7105; Strainer sleeves/Cover/Supports/Pins; Revision 3
Drawing SFS-PI-PA-7104; Strainer Sections and Details; Revision 1
Drawing SFS-PI-PA-7101; Strainer Master Core Tube Layouts; Revision 5
Drawing SFS-PI-PA-7100; Strainer Module Assembly: Revision 4
Drawing SFS-PI-GA-04; Strainer Cover and Pipe Layout; Revision 2
Drawing SFS-PI-GA-03; B Strainer; Revision 2

Drawing SFS-PI-GA-02; A Strainer; Revision 2
Drawing SFS-PI-GA-01; General Notes; Revision 2
Drawing SFS-PI-GA-00; Strainer Recirc Sump System; Revision 1
Drawing SK-04RH04-01; Containment Standpipe Support; Revision 0
Drawing SK-04RH04-02; Containment Standpipe Support; Revision 0
Drawing SK-04RH04-03; Cable Tray Support System Demolition; Revision 0
Drawing SK-04RH04-04; Cable Tray Support System Modification; Revision 0
Drawing SK-04RH04-05; Cable Tray Support System Modification; Revision 0
Drawing SK-04RH04-06; Cable Tray Support System Modification; Revision 0
Drawing SK-04RH04-07; Cable Tray Support System Modification; Revision 0

<u>Replacement RVCH</u> (71007)
Design Change 03RV05 Part 1; Replace Unit 1 and 2 Reactor Vessel Heads and Associated Components; Revision 1
Design Specification 418A07; Replacement RVCH; Revision 2
Design Specification 418A08; Control Rod Drive Mechanism; Revision 2
Document L5-01DV505; Prairie Island Unit 1, Replacement RVCH, Justification for Nonconformance Reports of Replacement RVCH; Revision 2
Document L5-01DV510; Prairie Island Unit 1, Replacement RVCH, Design Report; Revision 2
WCAP-16427-P, Revision 0, Addendum 2; Prairie Island Unit 1, Replacement RVCH - Design Report; dated January 2006
WCAP-16427-P, Revision 0, Addendum 1; Prairie Island Unit 1, Replacement RVCH - Design Report; dated November 2005
WCAP-16427-P; Prairie Island Unit 1, Replacement RVCH - Design Report; Revision 0
Calculation Note CN-RCDA-04-47; Prairie Island Units 1 and 2, Replacement RVCH - Analysis Procedure; Revision 2
Calculation Note CN-RCDA-04-75; Prairie Island Units 1 and 2, Replacement Head Project - Closure Head Flange ASME Leakage Evaluation; Revision 3
Calculation Note CN-RCDA-05-58; Prairie Island Units 1 and 2, Replacement RVCH - Fracture Evaluation; Revision 0
Calculation Note CN-RCDA-05-59; Prairie Island Units 1 and 2, Replacement RVCH - Closure Head Lifting Lug Stress Analysis; Revision 1
Calculation Note CN-RCDA-05-60; Prairie Island Units 1 and 2, Replacement RVCH - ASME Section XI Code Reconciliation; Revision 0
Calculation Note CN-RCUFW-04-7; Point Beach Unit 2, Replacement Head Project - Closure Head Flange ASME Code and Leakage Evaluation; Revision 1
Document PI-KCS-05-0001; Prairie Island Units 1 and 2, Control Rod Drive Mechanism, Design Report PI-KCS-04-0001, Revision 2, Addendum; Revision 2
Document PI-KCS-05-0003; Prairie Island Unit 1, Control Rod Drive Mechanism, Justification for Nonconformance Reports for Replacement Control Rod Drive Mechanism; Revision 1
Critical Design Characteristics 1439-CDC-001; RRVCH Replacement Internal dome Insulation; dated May 14, 2005
Critical Design Characteristics 1439-CDC-002; Modify Support Angles in Reactor Vessel External Insulation; dated May 14, 2005
Deviation Notice 62559; Prairie island Unit 1, Shroud Support Flange, Bolt Hole Diameters Out-of-Tolerance; December 13, 2005
Equivalent Engineering Change 1439; Replace Unit 1 and Unit 2 Reactor Vessel Head Internal Insulation; Revision 0

MHI Drawing L5-01DV109; Replacement RVCH, Closure Head and Adapter Housing Assembly; Revision 2
MHI Drawing L5-01DV171; Replacement RVCH, As-Built Drawing (RV Closure Head) 1/3; Revision 1
MHI Drawing L5-01DV172; Replacement RVCH, As-Built Drawing (RV Closure Head) 2/3; Revision 2
MHI Drawing L5-01DV173; Replacement RVCH, As-Built Drawing (RV Closure Head) 3/3; Revision 2
MHI CMTR UGC-CMTR-04-19; Certified Material Test Report, Unit 1 Replacement RVCH; dated December 1, 2004
Reactor Vessel Closure Head and Control Rod Drive Mechanisms; ASME NPT Component Certification; Mitsubishi Heavy Industries, Ltd; dated January 11, 2006

<u>Head Assembly Upgrade Package</u> (71007)
CAP 01003629; Generate Operating Experience Evaluation Report for NRC Regulatory Issue Summary 2005-25, "Control of Heavy Loads"; dated November 14, 2005
Design Change 03RV05 Part 2; Reactor Vessel Head Assembly Upgrade Package; Revision 1
Design Specification 418A34; Head Assembly Upgrade Package; Revision 6
Calculation 2005-05621; Analysis of Postulated Reactor Head Drop onto the Reactor Vessel Flange; Revision 3
Calculation ENG-CS-300; Support for CRDM Fan Disconnect Switch; Revision 1
Calculation ENG-CS-361; Evaluation of the Acceptability of the Reactor Vessel Head Lift Rig, Reactor Vessel Internals Lift Rig, Load Cell and Linkage to the Requirements of NUREG-0612 for Prairie Island Units 1 and 2; Revision 1
Calculation Note CN-RVHP-04-61; Prairie Island HAUP, Head Lift Rig Evaluation; Revision 4
Calculation Note CN-RVHP-04-74; Prairie Island HAUP - Structural Analysis for DW, Thermal Expansion, Seismic and LOCA Loadings; Revision 3
Calculation Note CN-RVHP-04-75; Prairie Island Units 1 and 2 - HAUP Radiation Shield and Support Ring Structural Analysis; Revision 5
Calculation Note CN-RVHP-04-78; Prairie Island Reactor Vessel Model: Units 1 and 2; Revision 0
Calculation Note CN-RVHP-04-89; Prairie Island HAUP, Cable Bridge No. 2 Structural Analysis; Revision 6
Calculation Note CN-RVHP-05-17; Prairie Island Units 1 and 2 - Evaluation of Non-Safety-Related Components for LOCA; Revision 3
Calculation Note CN-RVHP-05-43; Prairie Island HAUP Unit 1 ZX Piping Analysis; Revision 3
Calculation Note CN-RVHP-05-61; Prairie Island Unit 1 HAUP - Miscellaneous Hardware Seismic Evaluation; Revision 2
Deviation Notice 62033; Prairie island Unit 1, HAUP, Lift Leg Extension, False Cut, 1-1/2 Wide x 1-1/8 Long x 0.170 Deep; Revision 0
Drawing 10017E03 Sheets 1 though 4; Prairie Island Units 1 and 2, Head Assembly Upgrade Package, North Side Cavity Bridge Assembly; Revision 2
Drawing 10017E62 Sheets 1 though 4; Prairie Island Units 1 and 2, Head Assembly Upgrade Package, North Side Cavity Bridge Frame Subassembly; Revision 3
Drawing NF-38434-2; Reactor Building Unit 1, Reactor Vessel Steel Supports; Revision K
Drawing NF-38435; Reactor Building Unit 1, Reactor Vessel Supports - Plans, Sections and Details; Revision F
Drawing NF-38436; Reactor Building Unit 1, Reactor Vessel Column Supports - Sections and Details; Revision F

Drawing NF-38490-1; Reactor Building Unit 2, Reactor Vessel Column Supports: Plans, Sections and Details; Revision E
Drawing NF-38490-2; Reactor Building Unit 2, Reactor Vessel Steel Supports; Revision C
Drawing X-HIAW-1-384; Unit 1 - General Assembly; Revision K
Engineering Change Notice 03RV05-10; Requested Change to Anchor Bolt Size and Retention; Revision 0
Field Deviation Report FDR-PI1HAUP-01; Prairie Island Unit 1, CET Chiller Bridge Weld Does Not Meet AWS D1.1 Requirements; April 5, 2006
Maintenance Procedure D58.1.9; Unit 1 - Reactor Vessel Head Removal; Revision 11
Maintenance Procedure D58.2.9; Unit 2 - Reactor Vessel Head Removal; Revision 10

<u>Corrective Action Requests Initiated as a Result of NRC Inspection</u>
CAP 01025009; Evaluate Removal of Head Lift Height Restriction from USAR; dated April 19, 2006
CAP 01030203; Potential Non-Conservative Qualification of CRDM Cool Bridge; dated May 15, 2006
CAP 01030355; Review 50.59 Evaluation 1052; Revision 0 Bases to Remove Reactor Head Lift Restriction from USAR; dated May 16, 2006
CAP 01030740; HAUP LOCA II/I Acceptance Criteria Not Specified in Any Design Document; dated May 17, 2006
CAP 01031051; 50.59 Screen for LOCA II/I Conclusions Questioned; dated May 18, 2006

<u>Closure of URI 05000306/2005004-07</u>
CAP 00864144; NRC Head Replacement Questions; dated November 30, 2005
Calculation Note CN-RVHP-04-87; Prairie Island HAUP, Plenum Stress Qualification; Revision 3
Calculation Note CN-RVHP-04-87; Prairie Island HAUP, Plenum Stress Qualification; Revision 4
Calculation Note CN-RVHP-04-90; Prairie Island Units 1 and 2 HAUP, Cooling Shroud Structural Analysis; Revision 2
CAP 041407; Westinghouse NSAL 05-1 Issue, RCGVS and RVLIS Not Analyzed for LOCA Movements; dated March 17, 2005
CAP 043325; NRC Head Replacement Questions; July 5, 2005
Engineering Manual 1.2.3; Development of Design Calculations; Revision 10
Fleet Procedure FP-E-CAL-01; Calculations; Revision 0
Fleet Procedure FP-E-MOD-07; Design Verification and Technical Review; Revision 1
Fleet Procedure FP-E-MOD-11; Control of Design Interfaces; Revision 1
Nuclear Safety Advisory Letter NSAL-05-1; Reactor Vessel Head Assembly LOCA Loads; dated January 18, 2005
External Operating Experience 036997; NSAL-05-1, Reactor Vessel Head Assembly LOCA Loads; dated January 25, 2005
Root Cause Evaluation 0201; Adverse Trend in Minor Errors in Calculations; Revision 0

<u>Reactor Vessel Head Replacement Installation and Testing</u> (71007)
WO 00097597; Modify Unit 1 Equipment Hatch Platform/Rails; September 7, 2005
WO 00097616; Rig/Transfer RVCH and Replacement RVCH; July 26, 2005
Maintenance Standards Implementing Procedure MSIP 6003; Control of Heavy Load; Revision 4
Maintenance Procedure D58; Heavy Loads Program; Revision 31
Maintenance Procedure D58.1.10; Unit 1 - Reactor Vessel Head Replacement; Revision 9
CAP 01031457; Safety Issues During Head Lift; Lack of Co-worker Coaching
CAP 01031459; Weak ALARA Practices During Head Lift and Set

CAP 01031485; Unclear Procedure Guidance for Unit 1 D58
SP 1546; CRDM Timing Test; Revision 0

4OA7 Licensee-Identified Violation

CAP 01028790; PRA Configuration Assessed Incorrectly
CAP 01029449; Non-Safety-Related Parts Used in Safety-Related Application

LIST OF ACRONYMS USED

ADAMS	Agencywide Documents Access and Management System
ALARA	As-Low-As-Reasonably-Achievable
ASME	American Society of Mechanical Engineers
BACC	Boric Acid Corrosion Control
CAP	Corrective Action Program/Corrective Action Program Action Request
CFR	Code of Federal Regulations
CRDM	Control Rod Drive Mechanism
DAC	Derived Air Concentration
DRP	Division of Reactor Projects
EPRI	Electric Power Research Institute
ET	Eddy Current
GL	Generic Letter
HAUP	Head Assembly Upgrade Package
HEPA	High Efficiency Particulate Air
HRA	High Radiation Area
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IPEEE	Individual Plant Examination of External Events
IR	Inspection Report
ISI	Inservice Inspection
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
NCV	Non-Cited Violation
NDE	Nondestructive Examination
NEI	Nuclear Energy Institute
NMC	Nuclear Management Corporation, LLC
NRC	U.S. Nuclear Regulatory Commission
OPR	Operability Recommendation
PARS	Publicly Available Records
PINGP	Prairie Island Nuclear Generating Plant
PORV	Power Operated Relief Valve
RCGVS	Reactor Coolant Gas Ventilation System
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RIS	Regulatory Issue Summary
RPIP	Radiation Protection Implementing Procedure
RVCH	Reactor Vessel Closure Head
RVLIS	Reactor Vessel Level Indication System
RWP	Radiation Work Permit
SDP	Significance Determination Process
SG	Steam Generator
SI	Safety Injection System
SP	Surveillance Procedure
SSC	Structure, System, or Component
SWI	Section Work Instruction
TER	Technical Evaluation Report
TS	Technical Specifications
URI	Unresolved Item
USAR	Updated Safety Analysis Report
WO	Work Order